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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO MODIFY ITS NET METERING SERVICE AND TO INCREASE THE GENERATION CAPACITY LIMIT.	))))))	CASE NO. IPC-E-12-27

Idaho Conservation League

Direct Testimony of R. Thomas Beach

May 10, 2013

Q: Please state your name, address, and business affiliation.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: Please describe your experience and qualifications.

A: I have over 30 years of experience in utility analysis including advising three California Public Utilities Commissioners and serving as an expert witness in a wide range of utility proceedings. Prior to this experience I earned degrees in English and Physics from Dartmouth College and a Masters in Mechanical Engineering from the University of California, Berkeley. My curriculum vita is attached to this testimony as Exhibit 201.

Q: On whose behalf are you testifying in this proceeding?

A: I am appearing on behalf of the Idaho Conservation League (ICL). ICL intervened in this case because they are concerned that Idaho Power's proposed Schedules 6 and 8 are an unjustified change to the net metering program, Schedule 84.

Q: Have you previously testified or appeared as a witness before the Idaho Public Utility Commission?

A: No, I have not. However, I have testified on numerous occasions before state regulatory commissions in California, Colorado, Nevada, New Mexico, Oregon, and Virginia. Exhibit 201 includes a current list of the testimony that I have sponsored in state regulatory proceedings concerning electric and gas utilities. With respect to the net metering issues under consideration in this case, I have testified on issues concerning net energy metering (NEM) and solar economics in California, Colorado, New Mexico, and Virginia. I recently co-authored a major cost-benefit analysis of NEM in California, which is the largest solar market in the U.S.[1]

Q: Do you have any exhibits?

A: Yes. Exhibit 201 is my curriculum vita. Exhibit 202 is a report produced for the Vermont Public Service Department analyzing the costs and benefits of net metering for Vermont, including a literature survey of other similar cost/benefit studies. Exhibit 203 is a confidential exhibit containing my calculation of the costs and benefits of a hypothetical net metered solar system. Exhibit 204 is Idaho Power's response to ICL's production request number 1. Exhibit 205 is a portion of a presentation by Idaho Power showing the preliminary change in avoided costs between the 2011 IRP and the 2013 IRP.

Q: Please summarize your testimony.

A: Electric consumers have the right to install their own, privately-financed, on-site renewable distributed generation (DG) and to interconnect that generation with the grid, thus giving the DG customer the freedom to meet some or all of their energy needs.[2] Net energy metering (NEM) is a foundational policy that enables this freedom. NEM allows the DG customer to receive a retail rate credit when the DG output exceeds the customer's on-site use, essentially "running the meter backward." NEM is, at its essence, a billing arrangement which provides a simple way to calculate the bill for a DG customer, considering that the customer at times imports electricity from the grid and at other times exports power to the grid.

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[1] Beach, R. Thomas, and McGuire, Patrick G., *Evaluating the Benefits and Costs of Net Energy Metering in California* (January 2013), (hereafter "Crossborder NEM Study") Available at http://votesolar.org/wp-content/uploads/2013/01/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf

[2] This right is provided under, the Public Utilities Regulatory Policies Act of 1978 (PURPA). See 18 CFR §292.303.

My testimony responds to the Idaho Commission's request, when they initially approved the Schedule 84 net metering tariff, for a report comparing retail rates to the value of the net-metered generation. In 2002, Idaho Power proposed and the Idaho Commission approved Schedule 84 — Customer Energy Production — Net Metering. Since its inception, Schedule 84:

- charges customers the rate consistent with their class cost of service while the meter is running forward;
- pays customers the retail rate consistent with their class of service while the meter is running backward; and
- does not impose any monthly charges other than those provided on the customer's standard service schedule.[3]

When reviewing Schedule 84, the Idaho PUC Staff argued that crediting net metering generation at the full retail rate may "pay customers more than the actual value of the generation," causing non-participating ratepayers to subsidize the net metering participants.[4] In light of this alleged subsidy the Idaho Commission approved a cap on the overall program to limit any potential impacts. Critically, the Commission directed Idaho Power, when the cap was reached, to produce "a report regarding the required level of subsidization by non-participants" and the "differential between the net metering price it pays at retail rates and the wholesale cost of alternative power supplies."[5]

Responding to the Commission's directive, my testimony compares the retail rate credits paid to solar net metered customers (the primary costs of net metering) to the costs which Idaho Power avoids by not having to procure and deliver alternative power supplies to net metered customers (the benefits of net metering). Table 1 summarizes the costs and benefits that I have calculated. My analysis concludes that, for Idaho Power's ratepayers today, the benefits of net

[3] *See Order No. 28951* at 2, IPC-E-01-39.
[4] *Id* at 4.
[5] *Id* at 12.

metering significantly exceed the costs, by a factor of 1.6 to 1.9. In other words, my analysis shows that crediting NEM generation at the retail rate actually undervalues this new generation source.

Table 1: *Summary of Idaho Power NEM Costs and Benefits*
20-year Levelized $ per MWh

Costs	
Lost Utility Revenues	$81
Integration Costs	$4
Total Costs	**$85**
Benefits	
Energy	
2011 IRP	$ 92
2013 IRP (estimated)	$ 64
Capacity – both IRPs	$ 40
Transmission – both IRPs	$ 32
Total Benefits - 2011 IRP	**$ 164**
Total Benefits - 2013 IRP	**$ 136**
Benefit / Cost Ratio	
2011 IRP	**1.9**
2013 IRP	**1.6**

Q: Please characterize the basic analytic process which you have used for this cost / benefit analysis.

A: This analysis is a ratepayer impact measure (RIM) test, one of the standard cost-effectiveness tests that are widely used by utilities throughout the U.S. (including by Idaho Power) to evaluate the ratepayer impacts of Demand Side Management (DSM) programs.[6] Under the terms of the Memorandum of Understanding for Prudency Determination of DSM Programs, Idaho Power uses three primary cost-effectiveness tests: the total resource cost test (TRC), which "reflects the total benefits and costs to all customers (participants and non-

6 *See California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* (October 2001). Idaho Power's use of such tests is described in the 2011 IRP, Appendix C, at 66-67.

participants) in the [utility service territory:" the utility cost test (UTC), which "calculates the costs and benefits of the program from the perspective of . . . the utility implementing the program; and the participant cost test (PCT), which "assesses the costs and benefits from the perspective of the customer installing the measure."[7] The RIM test "examines the potential impact the energy efficiency program has on rates overall" including impacts to customers who do not participate in the DSM or net metering programs.[8] Because this is the strictest of the tests, Idaho Power is "not required to use the non-participant ("no losers") test."[9] A RIM score above one indicates that overall rates are likely to decrease due to the net metering program, as is the case with Idaho Power's net metering program.

Q: Why do you apply a method developed for evaluating DSM programs to evaluate NEM costs and benefits, when a NEM customer can go beyond reducing their own consumption and deliver excess energy to Idaho Power's system?

A: In practice a NEM customer is most similar to an energy efficient customer and is fundamentally different than an independent electrical generator seeking to sell their output to a utility. I observe that the majority of the output of a net metered DG system serves the customer's on-site load without ever touching the grid,[10] as illustrated in Figure 1, and in this respect looks to the utility like an energy efficiency (EE) or demand-side management (DSM) resource. By contrast, a qualifying facility or other independent electricity generator relies on the

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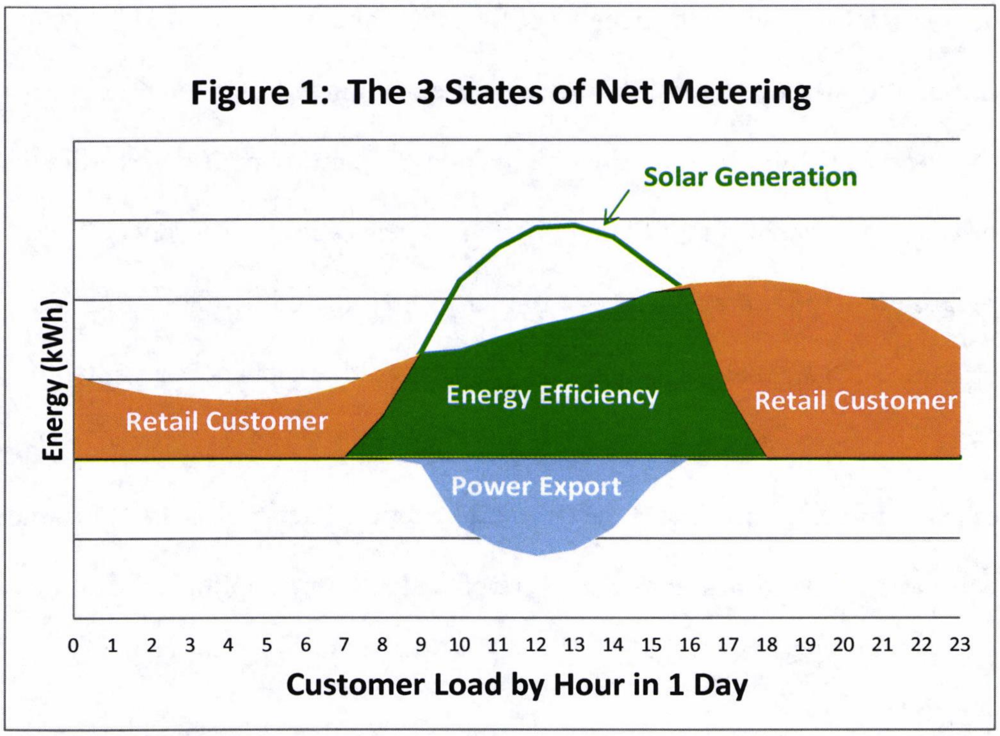
[7] *Order No 32331* at 9 – 10, IPC-E-11-05.
[8] National Action Plan for Energy Efficiency, *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers* at 3-6 (November 2008).
[9] *Order No 28894* at 7, IPC-E-01-13.
[10] The exact percentage used on-site will depend on the size of the solar DG system compared to the customer's load, and on the customer's load profile through the day. For the typical (con't) residential customer (such as shown in Figure 1), about 55% to 75% of the DG output is used on-site, with the rest exported to the grid.

grid to sell the output of their generation system. Because of the focus on serving on-site load, NEM should be evaluated in a manner that is consistent with how other demand-side resources are assessed.



Traditional DSM programs pay customers an incentive to reduce on-site loads. For NEM the "incentive" is crediting the small portion of the NEM customer's output that is exported to the grid, instead of paying a wholesale power price. This incentive is conceptually no different than a rebate, which is paid to a customer when the customer buys an energy-efficient air conditioner or agrees to manage his irrigation pumping loads. Those DSM programs are analyzed to ensure that the costs and benefits are balanced such that society as a whole benefits and other ratepayers are not unduly burdened. Similarly, the purpose of my analysis of Idaho Power's current NEM program is to ascertain whether the cost of NEM credits at the retail rate is offset by the benefits to other ratepayers from the reduced demand and the new source of power that the NEM customer brings to the grid.

Q: Have other state utility regulators accepted this analytical method?

A: Yes, although there are relatively few examples because only recently are states beginning to analyze net-metered DG. California uses the same set of cost-effectiveness tests and the same avoided cost calculator to analyze the benefits of EE, DSM, and net-metered DG resources.[11] The state of Vermont also used this approach to assess the economics of net metering in Vermont. I included this report as Exhibit 202 because of it includes a literature review of studies that have looked at the costs and benefits of NEM and distributed generation.[12] The key point is that such cost-effectiveness evaluations are widely used in many states, including Idaho, to evaluate DSM programs, so using such an analysis for net-metered DG builds on a widely-accepted framework.

Q: Over what time horizon should the cost and benefits of net-metered DG be analyzed?

A: As with other DSM measures as well as supply-side resource options, the evaluation should be over the life of the DG system. Accordingly, the analyses presented below are conducted over a 20-year period (2013-2032), and the results are expressed in terms of 20-year levelized costs and benefits. This also aligns with the 20-year horizon Idaho Power uses to evaluate utility resource options in the Integrated Resource Plan.

Q: Please describe how you calculate the "costs" of a NEM system in your analysis.

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[11] The California Public Utilities Commission (CPUC) has used this framework to evaluate the state's solar incentive program. *CSI Cost-Effectiveness Evaluation* (April 2011). Available at ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/csi/CSI%20Report_Complete_E3_Final.pdf The CPUC also has used this approach to do a more focused evaluation of net metering. *Net Energy Metering Cost Effectiveness Evaluation*, (March 2010). Available at http://www.cpuc.ca.gov/NR/rdonlyres/0F42385A-FDBE-4B76-9AB3-E6AD522DB862/0/nem_combined.pdf

[12] Exhibit 202, *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012* (Vermont Public Service Department, January 15, 2013).

A: The principal costs of DG are the revenues that the utility loses as a result of NEM customers serving their own loads and running the meter backward when they export power to the grid. Table 2 is an analysis of the lost revenues for a hypothetical Idaho Power residential customer with average usage who installs a 5.0 kW PV system in Boise and who pays the utility's standard three-tier residential rate. I used the industry-standard PVWATTS calculator from the National Renewable Energy Lab (NREL)[13] to project the hourly output of such a PV system, and then aggregated that output by month and by Idaho Power's seasonal and peak time periods. This PV output is presented in Table 3. Table 2 shows that the lost revenues are $644 per year in 2013, or about $78 per MWh. Assuming that rates escalate at 3% per year and using the utility's 7% discount rate, the 20-year levelized lost revenues are $81 per MWh.

I have also considered whether Idaho Power might incur additional costs to integrate solar DG resources into its system. Given the small amount of solar DG now on-line, such costs would appear to be very modest, perhaps negligible. A recent Idaho Power wind integration study reveals "customer demand is a strong determinant of Idaho Power's ability to integrate wind."[14] When wind generation occurs during low load periods, and as the amount of wind on the system reaches a high percentage of loads, integration costs increase. But Idaho Power's own IRP shows that the solar resources are a closer fit to the utility's loads. Further, the roughly 3 MW of NEM customers are far smaller than the several hundred MW of wind on Idaho Power's system. Other utilities in the western U.S. that have analyzed both wind and solar integration costs have found that solar integration costs are lower.[15] Accordingly, we assume that solar

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[13] The NREL *PVWATTS* calculator is available at: *http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/*

[14] Idaho Power *2011 IRP Update Wind Integration Study* at 7, (filed with the Idaho PUC in February of 2013).

[15] For example, Arizona Public Service (APS) has found wind integration costs to be $3.25 per MWh, and comparable solar costs to be $2.00 per MWh (in 2020). *APS 2012 Integrated Resource Plan*, at 32. Black & Veatch, "Solar Photovoltaic (PV) Integration Cost Study" (B&V Project No.

integration costs for Idaho Power are $4.00 per MWh, compared to the current wind integration costs of $6.50 per MWh.

174880, November 2012). Available at: http://www.solarfuturearizona.com/B&VSolarPVIntegrationCostStudy.pdf

Table 2: *Residential Solar DG Costs: Utility Lost Revenues or DG Customer Bill Savings*

Customer Bill Before Solar NEM System

	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Days	*365*	*31*	*28*	*31*	*30*	*31*	*30*	*31*	*31*	*30*	*31*	*30*	*31*
System Residential Loads (aMW)[16]		810	684	575	490	450	490	636	614	494	479	596	819
# of Residential Customers	410,877												
Average Usage (kWh)	12,683	1,467	1,119	1,041	859	815	859	1,152	1,112	866	867	1,044	1,483
Tier 1 (≤ 800 kWh)	9,600	800	800	800	800	800	800	800	800	800	800	800	800
Tier 2 (801-2,000)	3,083	667	319	241	59	15	59	352	312	66	67	244	683
Tier 3 (> 2,000 kWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Bills Before Solar ($)	**$969**	$112	$84	$77	$63	$59	$68	$96	$63	$63	$78	$113	$93

Customer Bill After Solar NEM System

NEM System Size (kW - AC)	5.0												
PVWATTS NEM Output (kWh)	8,296	348	470	678	801	922	954	1012	953	790	646	396	328
NEM Customer Grid Use (kWh)	4,386	1,119	648	363	57	-107	-95	140	159	75	222	648	1155
Tier 1 (≤ 800	3712	800	648	363	57	-107	-95	140	159	75	222	648	800

[16] The average residential usage is derived from the 2011 Expected Case Load Forecast. 2011 IRP at Appendix C, page 4. ICL used this estimate of average residential consumption to avoid disclosing the actual average use per customer that Idaho Power claims is confidential. Confidential Exhibit 203 performs the same analysis using the monthly average consumption for 2012 provided by Idaho

kWh)													
Tier 2 (801-2,000)	674	319	0	0	0	0	0	0	0	0	0	0	355
Tier 3 (> 2,000 kWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Bills After Solar ($)	**$324**	$84	$47	$26	$4	-$8	-$7	$11	$12	$5	$16	$47	$87

Customer Bill Savings or Utility Lost Revenue

DG Customer Bill Savings, or Utility Lost Revenues ($)	**$644**	$28	$37	$51	$58	$67	$76	$85	$80	$58	$47	$31	$26
Lost Revenues in $/kWh	***$0.078***												

Residential Tiered Rates

($/kWh)	**Summer**	**Winter**
Tier 1 (≤ 800 kWh)	$0.0784	$0.0724
Tier 2 (801-2,000)	$0.0958	$0.0805
Tier 3 (> 2,000 kWh)	$0.1152	$0.0900
Uses February 2013 rates.		

Table 3: *PV Output (kWh) for a 5 kW System in Boise, by Season and Peak period*

Month	Summer On-peak	Summer Mid-peak	Non-Summer On-peak	Non-Summer Mid-peak	Annual Total
January			298	50	348
February			403	67	470
March			581	97	678
April			687	114	801
May			790	132	922
June	399	554			954
July	437	575			1,012
August	410	542			953
September			677	113	790
October			553	92	646
November			339	57	396
December			281	47	328
Annual Total	1,246	1,671	4,610	768	8,296
Percent of Output	*15%*	*20%*	*56%*	*9%*	*100%*

Q: What are the primary benefits of net-metered DG systems for Idaho Power's ratepayers?

A: A net-metered PV system provides a new source of power for the Idaho Power system, and allows the utility to avoid energy, capacity, and transmission costs. Idaho Power avoids the cost of procuring and delivering energy when a NEM customer meets their own demand on-site, as well as when a NEM customer exports excess energy to be consumed by their neighbors. The vast majority of NEM customers use solar panels that provide energy coincident with Idaho Power's peak demands, thereby deferring or avoiding capacity additions. DG systems avoid transmission costs because the energy generation occurs at the point of consumption and any excess generation is delivered to the closest neighbor. Other potential benefits include avoiding distribution costs, market price mitigation benefits, and enhanced grid security.

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Q: What alternate energy costs did you use?

A: I calculated the benefits by applying the alternate or marginal costs taken principally from Idaho Power's 2011 Integrated Resource Plan (2011 IRP), from preliminary information which the utility has released on its 2013 IRP, and from Idaho Power's most recent general rate case filing. These are the alternate costs Idaho Power and the Idaho Commission use to evaluate demand-side programs. The use of the DSM alternate costs are appropriate given that the "primary thrust of net metering," like other demand-side programs, "is to provide customers the opportunity to offset their own load and energy requirements"[17] – in this case, by facilitating the installation of privately-financed on-site renewable generation.

Idaho Power expects the alternate energy costs for the 2013 IRP to be lower than those in its 2011 IRP. Accordingly, I have calculated DG / NEM benefits using both (1) the alternate energy costs from the 2011 IRP[18] and (2) an estimate of 2013 IRP alternate energy costs based on Idaho Power's October 2012 DSM Status Update.[19] To produce the 2013 IRP estimate, I reduced the 2011 summer on-peak and non-summer mid-peak alternate costs by 25%, and summer mid-peak and all off-peak rates by 45%, to reflect lower gas and GHG costs. Table 4 shows both sets of alternate energy costs. In Table 5, I apply these alternate energy costs to expected DG output by cost period to determine the total energy-related benefits. The 20-year levelized energy benefits from a PV system are $92 per MWh using the 2011 IRP alternate energy costs and $64 per MWh with the estimated 2013 IRP values.

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[17] *Order No. 28951* at 11.

[18] Exhibit 204, *Idaho Power's Response to Idaho Conservation League Production Request No. 1* (confirming the Company continues to use the 2011 IRP Alternate Costs for DSM resources); Appendix C, at 67-68 and Table DSM-2. The summer on-peak alternate costs reflect the variable costs of a simple-cycle combustion turbine; the alternate costs in other time periods are based on modeling of the regional power market.

[19] Exhibit 205, *Idaho Power's DSM Status Update* presented to the 2013 IRP Advisory Committee on October 11, 2012. Showing a preliminary estimate of lower avoided costs than 2011.

Table 4: *Idaho Power Alternate Energy Costs ($/MWh)*

Year	2011 Integrated Resource Plan				2013 Integrated Resource Plan			
	Summer On-peak	Summer Mid-peak	Not Summer On-peak	Not Summer Mid-peak	Summer On-peak	Summer On-peak	Not Summer On-peak	Not Summer On-peak
			Percent of 2011 IRP Cost =>		*75%*	*55%*	*75%*	*55%*
2011	60.89	54.42	55.21	38.22				
2012	63.32	60.74	61.61	42.87				
2013	76.15	65.06	64.89	45.74	57.11	35.78	48.67	25.16
2014	81.13	70.10	69.41	48.81	60.85	38.56	52.06	26.85
2015	102.02	83.09	82.13	61.71	76.52	45.70	61.60	33.94
2016	107.46	87.44	85.69	64.88	80.60	48.09	64.27	35.68
2017	112.71	92.77	90.50	69.13	84.53	51.02	67.88	38.02
2018	117.79	96.80	95.88	73.50	88.34	53.24	71.91	40.43
2019	122.76	102.71	101.44	78.51	92.07	56.49	76.08	43.18
2020	128.32	109.45	107.53	84.34	96.24	60.20	80.65	46.39
2021	134.04	114.80	113.45	89.30	100.53	63.14	85.09	49.12
2022	137.67	119.64	117.74	92.35	103.25	65.80	88.31	50.79
2023	142.80	130.75	128.30	100.59	107.10	71.91	96.23	55.32
2024	148.73	134.44	133.70	105.39	111.55	73.94	100.28	57.96
2025	155.25	143.49	140.64	109.95	116.44	78.92	105.48	60.47
2026	161.87	149.37	147.30	114.66	121.40	82.15	110.48	63.06
2027	168.70	154.60	153.26	118.05	126.53	85.03	114.95	64.93
2028	176.12	160.39	158.69	124.71	132.09	88.21	119.02	68.59
2029	183.85	166.21	165.50	131.51	137.89	91.42	124.13	72.33
2030	191.80	171.20	170.346	135.45	143.85	94.16	127.85	74.50
2031	203.74	181.84	180.88	144.78	152.80	100.01	135.66	79.63
2032	216.42	193.15	191.94	154.75	162.32	106.23	143.95	85.11
2013-2032 Levelized at 7%	**106.70**	**92.82**	**91.711**	**70.79**	**80.02**	**51.05**	**68.78**	**38.93**

Q: How did you value the capacity benefits of DG resources?

A: I assume that a PV system will contribute firm summer capacity equal to 60% of the system's nameplate (AC) capacity. Accordingly, a 5 kW PV system would have a firm capacity of 3 kW. I use the 2011 IRP capacity value of $94 per kW-year (escalated to 2013 $), and assume a summer peak loss factor of 13%.[20] As shown in Table 6, the resulting capacity-related alternate cost for PV is $40 per MWh of PV output.

Q: Isn't PV a "non-firm" source of power, such that it should receive no capacity value?

A: No. Idaho Power's own 2013 IRP screening data assigns a summer on-peak capacity for distributed PV of 75% of these systems' nameplate capacity; thus, the utility assumes that 10 MW of 4 kW PV systems distributed across southwest Idaho would have a summer on-peak capacity of 7.5 MW.[21] There have been many studies of the capacity value of solar PV, across the U.S., employing sophisticated techniques such as the use of reliability models to calculate the effective load carrying capacity (ELCC) of solar resources.[22] Idaho Power's IRP assumption that distributed PV has a capacity value of 75% of nameplate is probably too high even on its

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[20] *Idaho Power 2011 IRP,* Appendix C at 69, Table DSM-1.

[21] *Idaho Power Supply-Side Resource Operating Inputs,* Presented to the 2013 IRP Advisory Committee on December 13, 2012. Available at: http://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2013/DecMtgMaterials/SupplySideResourceStack_PeakCapacity.pdf

[22] These studies include:

- Xcel Energy Services, Inc, *An ELCC Analysis for Estimating the Capacity Value of Solar Generation Resources on the Public Service Company of Colorado System,* (February 2009). A vailable at: http://www.solarfuturearizona.com/PSCO_Solar_ELCC_report_020909.pdf
- Hoff/Perez, Clean Power Research, *Energy and Capacity Valuation of Photovoltaic Power Generation in New York,* (March 2008). Available at: bit.ly/dPP2J1
- Hoff/Perez, Clean Power Research, *Determination of Photovoltaic Effective Capacity for New Jersey,* (June 2012). Available at http://www.cleanpower.com/resources/pv-elcc-new-jersey/
- Hoff/Perez, Clean Power Research, *Determination of Photovoltaic Effective Capacity for Nevada Power,* (March 2012). Available at http://www.cleanpower.com/resources/pv-elcc-nevada-power/

summer-peaking system, particularly for fixed array PV systems. A firm PV capacity value of 60% of nameplate is more reasonable given the range of capacity values for PV calculated in the available PV ELCC studies.

Q: Does solar DG avoid transmission costs?

A: Yes. Transmission costs are avoided because NEM generation is either used on-site or is exported and immediately consumed by the NEM customer's neighbors without loading the transmission system. DG at the distribution level which serves local loads in Idaho Power's service territory will reduce demand on Idaho Power's transmission system. It is particularly important to include avoided transmission costs given that Idaho Power is transmission-constrained during summer peak periods, the Boardman to Hemingway Transmission line was the preferred resource in the 2011 IRP, and Idaho Power continues to pursue a partnership in the Gateway West transmission line.[23]

Q: Doesn't Idaho Power incur additional transmission and distribution (T&D) costs either to serve or to accept power from net metered DG customers?

A: No. When the DG customer's meter runs forward, the DG customer pays for that service at the full retail rate, including the full costs of the utility's T&D service. When the DG customer is exporting and the meter runs backward, the DG customer functions as a generator, selling power to Idaho Power at a price equal to the retail rate. As with any other generator from which Idaho Power purchases energy, the utility takes title to the power at the DG customer's meter and then delivers the power over its distribution system to other customers – the DG customer's immediate neighbors. Idaho Power then sells that power to the neighbors and receives its full retail rate in compensation – including the full retail T&D service charges – even though the

[23] *Idaho Power 2011 IRP* at 6 – 7; http://www.gatewaywestproject.com/.

utility has moved the power only a short distance without the use of its transmission system. In sum, the utility is more than fully compensated for all use of its T&D system associated with the services it provides to a net metered customer, and the transmission system costs which such a transaction avoids should be accounted for as a benefit in determining whether the full retail rate is the "right" price for net metered DG exports.

Q: How have you quantified such avoided transmission costs?

A: Idaho Power presented a marginal cost study in its most recent general rate case.[24] This study includes the utility's long-term marginal transmission costs – in other words, the investment-related costs that the utility will save if demand on its transmission system is reduced – based on the transmission capital budget over the 2011-2020 period. These marginal transmission costs are shown in Table 5.

Table 5: *Marginal Transmission Costs*

Month	$ per kW-year
January	2.39
February	2.29
March	3.48
April	0.96
May	12.59
June	**27.70**
July	**32.75**
August	**23.02**
September	20.38
October	6.66
November	6.93
December	33.85
Summer Total	**83.47**

Solar generation peaks on summer afternoons when Idaho Power's demand is also high. As a result, solar PV has particular value in avoiding transmission costs during Idaho Power's

[24] *2011 Marginal Cost Analysis*, Larkin Workpapers at 59-66, IPC-E-11-08, (April 28, 2011 memo from Scott Wright to Matt Larkin).

summer peak months (June – August). Accordingly, I used the June – August data on marginal transmission costs (escalated to 2013 $) to calculate the transmission benefits of solar DG, which are about $30 per MWh, as summarized in Table 6.

Q: Please summarize the benefits of net-metered solar DG.

A: Table 6 summarizes these benefits -- $163 per MWh using the 2011 IRP alternate energy costs and $135 per MWh using the estimated 2013 IRP alternate energy costs.

Table 6: *Avoided Cost Benefits for a 5 kW System by Seasonal and Peak Period*

	Summer On-peak	**Summer Mid-peak**	**Not Summer On-peak**	**Not Summer Mid-peak**	**Annual Total**
Solar DG Output	1,246	1,671	4,610	768	8,296
Energy - 2011 IRP					
Alternate Energy (20-yr level $/MWh)	$106.7	$92.82	$91.71	$70.79	
Energy ($)	$133	$155	$423	$54	$765
Energy Value ($/MWh)					$92.25
Energy - 2013 IRP					
Alternate Energy (20-yr level $/MWh)	$80.02	$51.05	$68.78	$38.93	
Energy ($)	$100	$85	$317	$30	$532
Energy Value ($/MWh)					$64.14
Capacity					
System Size	5.0 kW				
Firm Solar (%)	60%				
Firm Solar (kW)	3.0 kW				
Capacity Alternate Cost ($/kW-yr)	$98.76				
Summer Peak Loss %	13%				
Capacity Value ($ and $/MWh)	$335				$40.35
Transmission					
Firm Solar (kW)	3.0 kW				
Summer Transmission Marginal Cost ($/kW-yr)	$87.70				
Transmission Value ($ and $/MWh)	$263				$31.71
Total Value - 2011 IRP					**$164.32**
Total Value - 2013 IRP					**$136.20**

Q: What is the benefit-to-cost ratio for net-metered DG?

A: As shown in Tables 1 and 6, the benefit-to-cost ratio for net-metered DG ranges from 1.6 (2013 IRP) to 1.9 (2011 IRP). I note that net-metered DG is cost-effective on an energy basis alone using the 2011 IRP alternate energy costs.

Q: What would be the annual benefits for Idaho Power's non-participating ratepayers if 15 MW of net-metered solar DG were to be installed in Idaho Power's territory?

A: From Table 1, the net benefits of solar DG are $51 per MWh based on the 2013 IRP alternate energy costs. The output of 15 MW of solar DG is 24,900 MWh per year. Thus, the annual benefits from 15 MW of solar DG would be $1.3 million per year.

Q: Do you consider your assessment of the benefits and costs of solar DG conservative?

A: Yes. First my analysis uses the RIM test, which is widely considered the most conservative measure of the cost effectiveness of DSM programs. The RIM includes as a "cost" Idaho Power's forgone revenue attributable to a NEM customer who merely reduces their energy demands, but still is a net purchaser of electricity, instead of just focusing on a NEM customer's export of excess energy. Second, my analysis does not include additional benefits that other states have quantified and accepted. Both of these factors would increase the benefit-to-cost ratio.

Many utilities, including Idaho Power, do not use the RIM test to decide whether to implement energy efficiency programs. One reason is that the RIM test includes as a cost Idaho Power's forgone revenues due to reduced energy bills.[25] But like DSM programs, the majority of the output of a NEM system serves the customer's on-site load and never touches the grid (the "energy efficiency" portion of Figure 1). From the perspective of the impacts on the grid and on other ratepayers, this portion of the DG output is akin to the installation of an energy efficiency

[25] *NAPEE* at 3-6.

measure, or to the customer simply choosing to use less power, and no utility would single out a particular customer for extra charges if that customer decided to reduce his use of the utility's product. Further, customers have PURPA rights to install renewable DG on their premises and to serve their own load. From this perspective, it is only the exported portion of a NEM system that impacts the grid or non-participating ratepayers. A more precise RIM evaluation of NEM should focus only on the power exports, instead of the entire output of system, as my analysis does.[26]

However, such an "export-only" analysis is more complex and must be done on an hourly basis, as the amount of hourly exports depends on the size of the PV system relative to the customer's load and on the hourly profiles of the customer's PV production and load. Because NEM exports tend to occur in the afternoon when the power is most valuable, the per unit benefits of NEM exports typically are larger than the per unit benefits of the entire DG output. Thus, an export-only evaluation of NEM for Idaho Power would be likely to produce an even higher benefit / cost ratio that those which I have calculated above.

Second, my analysis does not include a number of benefits of solar DG that have been quantified and included in studies performed in other states. Other studies, such as the California cost / benefit studies referenced above, have included avoided distribution costs, which can be more difficult to analyze because the data on when distribution circuits peak and when they are expected to reach capacity are hard to obtain and highly location-specific. Other benefits which have been quantified include:

- **Price mitigation benefits.** Lower demand for electricity (and for the gas used to produce the marginal kWh of power) has the broad benefit of lowering prices across the gas and electric markets in which the utility operates.[27]

[26] The cost-benefit evaluations of NEM that have been conducted in California, as referenced in Footnote 8 above, have focused exclusively on NEM exports.
[27] For example, a Lawrence Berkeley National Lab study has estimated that the consumer gas bill savings associated with increased amounts of renewable energy and energy efficiency, expressed

- **Grid security.** Renewable DG resources are installed as many small, distributed systems and thus are highly unlikely to fail at the same time. They are also located at the point of end use, and thus reduce the risk of outages due to transmission or distribution system failures. This reduces the economic impacts of power outages.

- **Economic development.** Renewable DG produces more local job creation than fossil generation, enhancing tax revenues.

One study of several eastern U.S. markets estimated these benefits collectively to be from $100 to $140 per MWh.[28] Given that the benefits I have quantified are decisively higher than the costs, I have not tried to calculate these additional benefits for the Idaho Power system.

Q: Does this conclude your direct testimony?

A: Yes, it does.

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in terms of $ per MWh of renewable energy, range from $7.50 to $20 per MWh. Wiser, Ryan; Bolinger, Mark; and St. Clair, Matt, *Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency* at ix, (January 2005). Available at: http://eetd.lbl.gov/EA/EMP

[28] Hoff, Norris and Perez, *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania,* at Table ES-2 (November 2012). Available at: http://mseia.net/site/wp-content/uploads/2012/05/MSEIA-Final-Benefits-of-Solar-Report-2012-11-01.pdf

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO MODIFY ITS NET METERING SERVICE AND TO INCREASE THE GENERATION CAPACITY LIMIT.	))))))	CASE NO. IPC-E-12-27

Idaho Conservation League

Direct Testimony of R. Thomas Beach

May 10, 2013

EXHIBIT 201

CURICULUM VITA FOR R. THOMAS BEACH

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the western U.S., Canada, and Mexico.

Since 1989, Mr. Beach has participated actively in most of the major energy policy debates in California, including renewable energy development, the restructuring of the state's gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning California's large independent power community. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of PURPA.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning California's Renewable Portfolio Standard program, including the calculation of the state's Market Price Referent for new renewable generation. He has also worked for the solar industry on the creation of the California Solar Initiative (the Million Solar Roofs), as well as on a wide range of solar issues in other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, electric transmission and interconnection issues, property tax matters, standby rates, QF efficiency standards, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CPUC

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

   - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

   - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

   - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

   - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

   - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar powerplants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

- *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

- *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

- *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

- *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

- *Natural gas rate design issues; rate parity for solar power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

- *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

- *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

- *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    • *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    • *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    • *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    • *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

- *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

- *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

- *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

- *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

- *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

- *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

    - *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

    - *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

    - *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

    - *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

    - *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

63. a. Phase II Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

- *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

67. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

- *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
   b. Supplemental Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
   c. Supplemental Prepared Reply Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

   - *Local reliability benefits of a new natural gas storage facility.*

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Colorado Solar Energy Industries Association and the Solar Alliance, (Docket No. 09AL-299E – October 2, 2009).

   - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Vote Solar Initiative and the Interstate Renewable Energy Council, (Docket No. 11A-418E – September 21, 2011).

   - *Development of a community solar program for Xcel Energy.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

   - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

   - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony of R. Thomas Beach on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)

    - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the New Mexico Independent Power Producers, (Case No. 11-00265-UT, October 3, 2011)

    - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

    - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011)

    - *Standby rates for net-metered solar customers, and the cost-effectiveness of net metering.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO MODIFY ITS NET METERING SERVICE AND TO INCREASE THE GENERATION CAPACITY LIMIT.	))))))	CASE NO. IPC-E-12-27

Idaho Conservation League

Direct Testimony of R. Thomas Beach

May 10, 2013

EXHIBIT 202

EVALUATION OF NET METERING IN VERMONT CONDUCTED PURSUANT TO ACT 125 OF 2012

VERMONT PUBLIC SERVICE DEPARTMENT
JANUARY 15, 2013

Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012

Public Service Department
January 15, 2013

1 Introduction

Act 125 of the 2012 Vermont legislative session directed the Public Service Department (Department) to complete an evaluation of net metering in Vermont:

> *No later than January 15, 2013, the department of public service (the department) shall perform a general evaluation of Vermont's net metering statute, rules, and procedures and shall submit the evaluation and any accompanying recommendations to the general assembly. Among any other issues related to net metering that the department may deem relevant, the report shall include an analysis of whether and to what extent customers using net metering systems under 30 V.S.A. § 219a are subsidized by other retail electric customers who do not employ net metering. The analysis also shall include an examination of any benefits or costs of net metering systems to Vermont's electric distribution and transmission systems and the extent to which customers owning net metering systems do or do not contribute to the fixed costs of Vermont's retail electric utilities. Prior to completing the evaluation and submitting the report, the department shall offer an opportunity for interested persons such as the retail electric utilities and renewable energy developers and advocates to submit information and comment.*

The Department undertook several steps to address the legislative request and evaluate Vermont's net metering statute, rules, and procedures. Background and current statistics regarding net metering in Vermont are presented in Section 2 of this report. Section 3 describes the analysis the Department conducted to evaluate whether, and to what extent, customers employing net metering are subsidized by other customers. Section 4 concludes the report with a general assessment of the state's net metering statute, rules, and procedures.

The Department issued a Request for Information, focused on the cross-subsidization analysis but welcoming comments on all aspects of the study, on September 17, 2012. The results and analysis reported here were informed by comments submitted by eleven interested persons, organizations, and businesses (including utilities and renewable energy advocates). The Department also held several meetings with commenters to better understand their comments and solicit further information. The Department also received stakeholder comments on both the draft report document and draft spreadsheet tool, both of which were released on December 21, 2012.

2 Background

2.1 A Brief History of Net Metering in Vermont

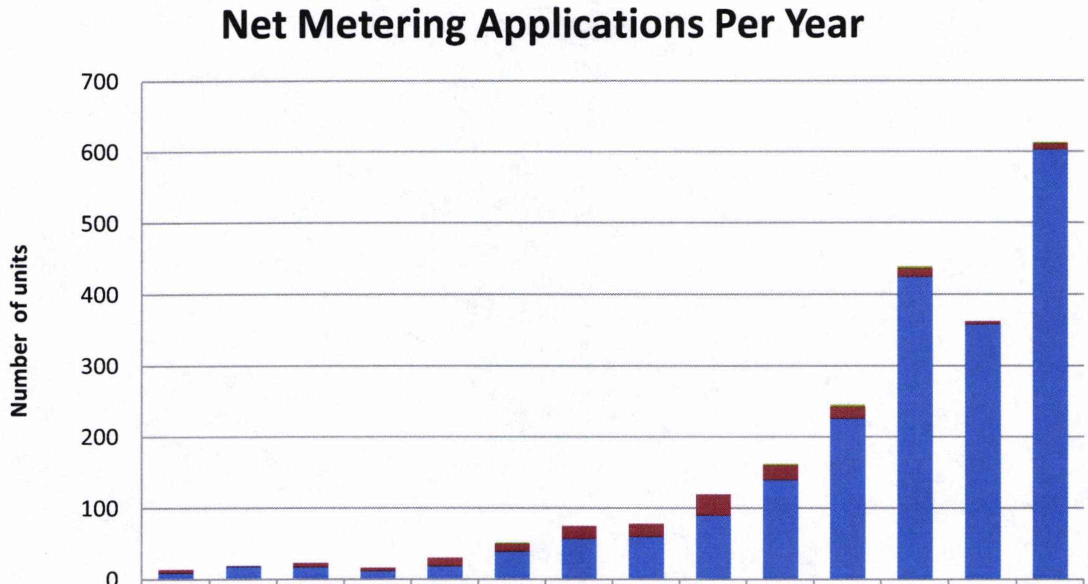
The 1998 legislative session enacted a net metering law (30 V.S.A. §219a), requiring electric utilities to permit customers to generate their own power using small-scale renewable energy systems of 15 kW or less (including fuel cells using a renewable fuel). Farm systems were allowed to be larger, with a cap of 100 kW. Any power generated by these systems could be fed back to the utility, running the electric meter backwards, if generation exceeded load at any given time.

Amendments in 1999, 2002 and 2008 permitted the installation of more net metered capacity, increased the allowable size of systems, and added the use of non-renewably fueled combined heat and power units of 20 kW or less. Beginning in 2002 “group net metering” was allowed, but was restricted to farmers. The 2008 amendments lifted this restriction, increased the permissible size per installation to 250 kW, simplified the permitting process for systems under 150 kW, and raised the ceiling on the total installed capacity from one percent to two percent of peak load. In 2011, the Vermont General Assembly expanded the permissible size limit per installation to 500 kW, simplified the administration for net metering groups, allowed a registration process for photovoltaic (PV) systems 5 kW and under, increased the overall net metering capacity cap per utility to 4 percent of the 1996 utility system peak or previous year’s peak (whichever is higher), and created a solar credit payment for all customers who have installed PV net metered systems. The solar credit payment has the effect of increasing the value of generation to net metered customers up to 20 cents per kWh in the year the system is installed.

During the 2012 session the registration process was expanded to PV projects 10 kW and under, and the process for group net metering billing and monetization of credits was clarified.

2.2 Status of Net Metering in Vermont

Net metering has experienced rapid growth over the last four years as the demand for local renewable energy has grown, costs have come down, and access to renewables has broadened. As can be seen in Figure 1, solar PV has had the most substantial growth of all the renewable technologies. The number of PV systems applying for net metering permits annually has grown by a factor of more than four since 2008.



	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Methane	0	0	0	0	0	1	0	0	0	1	2	2	0	2
Wind	5	1	6	4	11	11	18	18	29	21	17	12	4	8
Solar	9	18	17	12	19	39	57	60	90	140	226	425	358	603

Figure 1. *Number of net metering applications & registrations annually. (2012 data as of 12/5/12.)*

With the recent rise in number of PV installations, solar now accounts for almost 88% of all net metering systems. Wind turbines represent under 8% of the systems and hydro just 3% (see figure 2.)

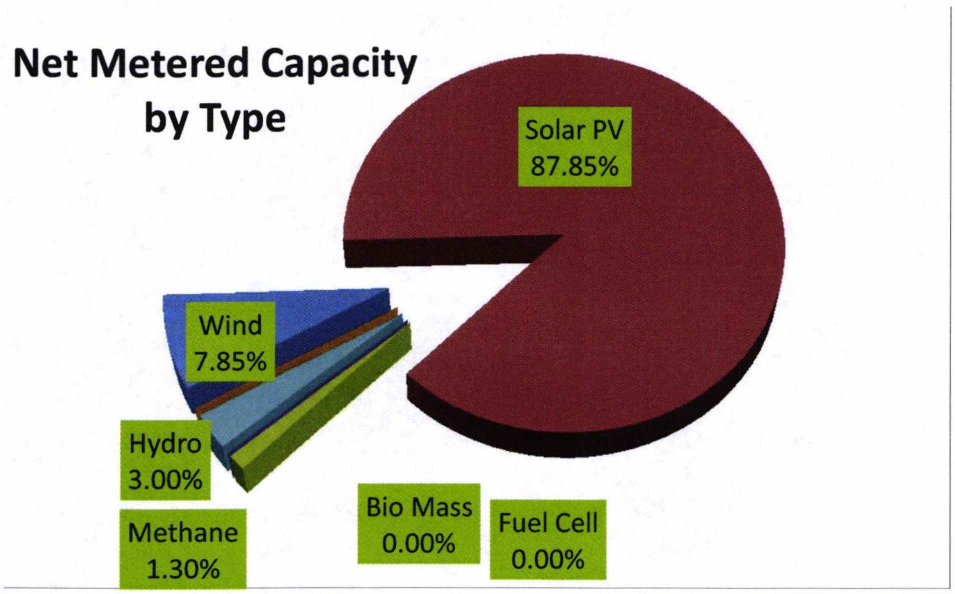
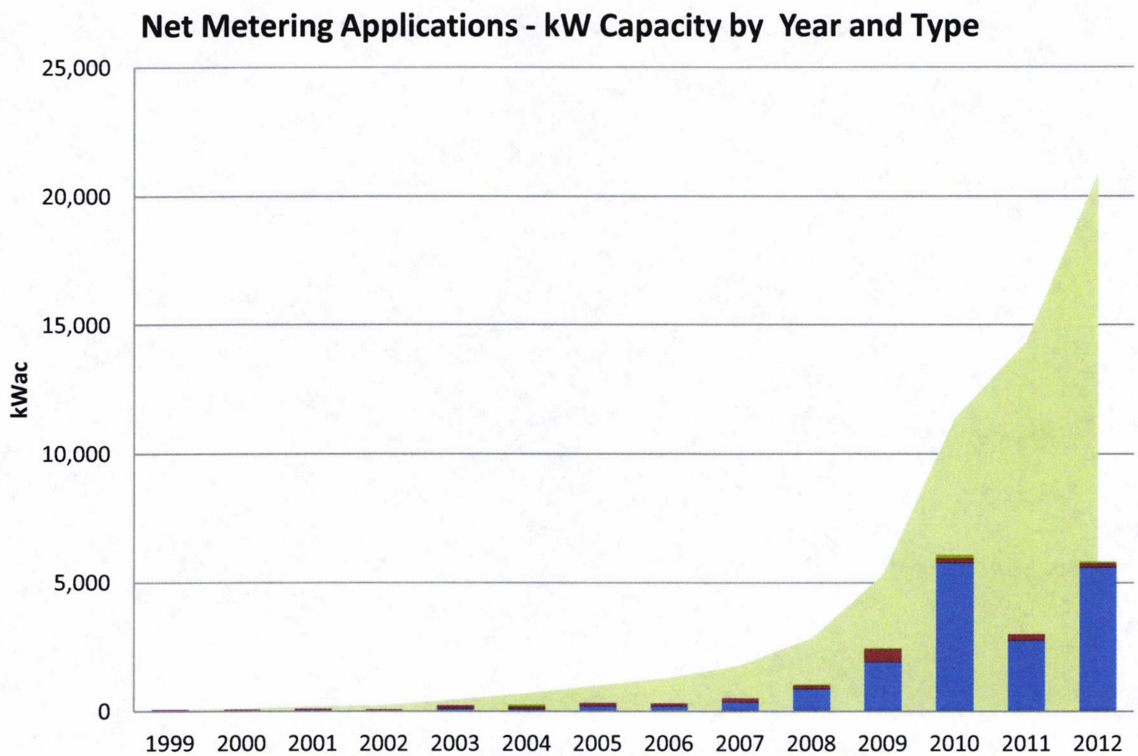


Figure 2. *Net metering applications & registrations by technology type.*

To date, there have been no net metered fuel cells or combined heat and power systems in Vermont.

The exponential increase in the number of PV system installations has driven not only the overall number of net metered systems but also the total growth of net metered system capacity[1] to over 20 MW (see figure 3).



	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Cumulatve Capacity	54.85	103.59	196.35	244.56	457.49	703.07	1009.9	1303.2	1797.0	2834.7	5304.9	11391.	14376.	20910.
Methane	0.00	0.00	0.00	0.00	0.00	65.00	0.00	0.00	0.00	19.00	39.00	126.75	0.00	69.30
Wind	31.91	9.50	27.95	30.00	98.50	83.94	118.51	101.51	143.29	144.44	491.91	179.55	223.50	137.48
Solar	22.95	39.24	64.81	18.22	114.43	96.64	188.34	191.81	350.55	874.18	1921.0	5780.2	2761.5	5611.0

Figure 3. *Capacity of net metering applications by type. (2012 data as of 12/5/12.)*

The capacity histogram (figure 4) shows that 59% of net metering systems permitted to date are less than 5 kW, 26% are between 5-10 kW and fewer than two percent are larger than 100kW.

[1] The capacity of a generator is the maximum output that the generator is capable of producing. It is an instantaneous measure, and measured in Watts, kilowatts (kW), megawatts (MW), etc. Energy production is measured over time – a 1 kW generator operating at that level for an hour produces one kilowatt-hour (kWh) of energy. Vermont's summer peak load is near 1000 MW, and the state uses about 5.5 terawatt-hours each year.

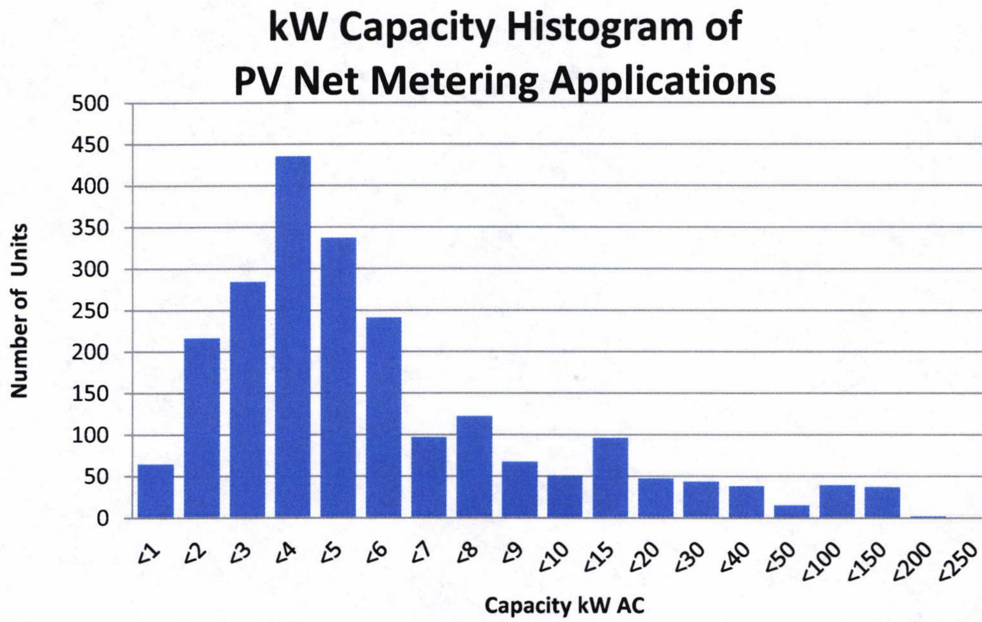


Figure 4. *Capacity (in kW AC) of all net metered PV system applications*

While the growth has been rapid and 20MW of small net metered systems represents a level of success that some didn't think would be achieved, it represents a very small fraction of Vermont's overall electrical portfolio. Only one utility (Washington Electric Cooperative) has more than 1% of their customers participating in net metering. There are some smaller utilities that are approaching the 4% capacity cap, but it is important to remember that the cap is based on capacity and not power production. Net metering systems produce less than 1% of the power Vermont uses each year or about 35 GWh per year[2].

3 Cross-Subsidization Analysis

This section describes the quantitative analysis conducted by the Department to examine the question raised explicitly in Act 125: "*... the report shall include an analysis of whether and to what extent customers using net metering systems under 30 V.S.A. § 219a are subsidized by other retail electric customers who do not employ net metering.*" In conducting this analysis, the Department was greatly aided by information and suggestions received from numerous stakeholders through written comments, data submittals, and meetings.

3.1 Literature review

In order to frame the analysis for determining whether net metering represents a "cost-shift" from non-participating ratepayers to net metering customers, the Department conducted a broad-based literature review of relevant papers and studies. This review included over two dozen publications from a wide variety of sources, including the National Renewable Energy Laboratory (NREL), the Solar America Board

[2] In 2011, Vermont utilities sold 5,554 GWh of electricity to their customers.

for Codes and Standards (Solar ABCs), and a number of states and utilities on either the subject of net metering benefits generally, or specifically on the rate impacts of net metering. Few of the publications reviewed were directly comparable with each other, or with the specific net metering rules and regulations in Vermont. However, information gleaned from these publications provided context that informed assumptions made in the Department model.

One of the challenges facing Vermont is that the only one other state – California – has conducted a full analysis of the cost-shift question (i.e., a full cost-benefit analysis) from a utility and ratepayer perspective. The California study[3] (and its subsequent updates[4,5]), along with two prior values-only studies performed for specific utilities (Arizona Public Service[6] and Austin Energy[7,8]) form the basis for a generalized methodology for analyzing the costs and benefits of net metering proposed by the Solar America Board for Codes and Standards[9]. This methodology, however, only looks at exported (rather than gross) generation from net-metered solar photovoltaic systems. For reasons explained below, Vermont has chosen to look at gross generation, and at generation from a number of allowed types of net metering technologies – not only solar. Therefore, the methodology serves as a good guidepost and checkpoint for our work, but not an exact template.

Three other relevant statewide studies have been performed: two in New York and one in Pennsylvania/New Jersey. One of the New York studies is a broad review of the benefits and costs to ratepayers of increasing in-state solar capacity to 5,000 MW by 2025[10]; while the other looks at the overall costs and benefits of distributed solar to ratepayers and taxpayers in the New York City area[11]. The PA/NJ study is similar to the latter[12]. The assumptions and methodologies used in these studies were also helpful in framing our analysis.

Table 1 below summarizes the results of relevant publications. Each study is unique, with distinct definitions for the costs and benefits analyzed. In many cases, costs and benefits not included in this

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[3] Energy and Environmental Economics, Inc. (2010). *Net energy metering (NEM) cost effectiveness evaluation (E3 study)*. Available at http://www.cpuc.ca.gov/PUC/energy/DistGen/nem_eval.htm.

[4] Beach, Thomas R. and Patrick G. McGuire (2012). *Re-evaluating the Cost-Effectiveness of Net Energy Metering in California*. Berkeley, CA: Crossborder Energy.

[5] Beach, Thomas R. and Patrick G. McGuire (2012). *Evaluating the Benefits and Costs of Net Energy Metering for Residential Customers in California*. Berkeley, CA: Crossborder Energy.

[6] *Distributed Renewable Energy Operating Impacts and Valuation Study* (2009). Seattle, WA: R.W. Beck.

[7] Braun, Jerry, Thomas E. Hoff, Michael Kuhn, Benjamin Norris, and Richard Perez (2006). *The Value of Distributed Photovoltaics to Austin Energy and the City of Austin.* Napa, CA: Clean Power Research, LLC.

[8] Harvey, Tim, Thomas E. Hoff, Leslie Libby, Benjamin L. Norris, and Karl R. Rabago (2012): *Designing Austin Energy's Solar Tariff Using a Distributed PV Value Calculator*. Austin, TX and Napa, CA: Austin Energy and Clean Power Research.

[9] Keyes, Jason B. and Joseph F. Wiedman (2012). *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering*. Solar America Board for Codes and Standards, http://www.solarabcs.org/about/publications/reports/rateimpact/pdfs/rateimpact_full.pdf.

[10] *New York Solar Study: An Analysis of the Benefits and Costs of Increasing Generation from Photovoltaic Devices in New York* (2012). Albany, NY: New York State Energy Research and Development Authority.

[11] Hoff, Thomas E., Richard Perez, and Ken Zweibel (2011). *Solar Power Generation in the US: Too Expensive, or a Bargain?* Albany, NY: Clean Power Research, LLC.

[12] Hoff, Thomas E., Benjamin L. Norris, and Richard Perez (2012). *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania.* Albany, NY: Clean Power Research, LLC.

table are discussed. Additional details of select studies are provided in a more extensive literature review document, posted at http://publicservice.vermont.gov/topics/renewable_energy/net_metering. Details of this Public Service Department study are included in Table 1 for comparison purposes.

Table 1: *Comparison of methodology and included costs and benefits in the relevant literature.*

Study	Test Perspective	Generation analyzed	Costs Analyzed: Net metering bill credits	Costs Analyzed: Program administration costs	Benefits Analyzed: Avoided energy purchases	Benefits Analyzed: Avoided capacity purchases	Benefits Analyzed: Avoided T&D line losses	Benefits Analyzed: Avoided T&D investments /O&M	Benefits Analyzed: Environmental benefits	Benefits Analyzed: Natural gas price hedge	Benefits Analyzed: Avoided RPS purchases	Benefits Analyzed: Reliability benefits (ancillary services and VAR support)	Notes
Solar ABCs 2012 (generalized methodology)	Utility/non-participating ratepayers	Exported energy only	X	X	X	X	X	X	X	X	X	X	Generalized methodology based on E3, Austin, and APS studies
E3 (for CA CPUC, 2010)	Utility/non-participating ratepayers	Exported energy only	X	X	X	X	X	X	X		X	X	Benchmark study for cross-subsidization evaluations
Crossborder (update to E3 study, 2012)	Utility/non-participating ratepayers	Exported energy only	X	X	X	X	X	X	X		X	X	Update to E3 based on interim restructuring of PG&E rate structures; results net cost 1/7 of that found in 2010
Crossborder 2 (2nd update, October 2012)	Utility/non-participating ratepayers	Exported energy only	X	X	X	X	X	X	X		X	X	Second update using same methodology as first but instead looking at all three IOU territories; still a small net cost in PG&E but more than offset by net benefits in SCE and SDG&E
Austin Energy (Clean Power Research, 2006, updated in 2012)	Utility/non-participating ratepayers	Gross output	N/A	N/A	X	X	X	X	X	X			Values-only study looking at distributed (not just net metered) PV; looked at reactive power control and disaster recovery values but not included in final results
APS (R.W. Beck, 2008)	Utility/non-participating ratepayers	Gross output	N/A	N/A	X	X	X	X				X	Values-only study looking at distributed (not just net metered) PV and also residential solar hot water & commercial daylighting systems
Perez (for NYC area, 2011)	Utility/non-participating ratepayers AND state/society	Gross output	N/A	N/A	X	X	X	X	X	X		X	For distributed PV; other costs analyzed: stream of revenues for devleoper to break even, and costs to manage non-controllable solar for reliability. Other benefits analyzed: long-term societal value, economic growth value
NYSERDA/NYDPS (2012)	Utility/non-participating ratepayers	Gross output	N/A	N/A	X	X	X	X	X		X		Costs/benefits of achieving 2,500 MW PV by 2020 and 5,000 MW by 2025; other costs analyzed: lifetime average energy costs of all scales of PV, plus admin costs of state solar incentive program; other benefits analyzed: prices suppresion, maroeconomic/jobs impacts
Clean Power Research (Perez for NJ & PA, 2012)	Utility/non-participating ratepayers AND state/society	Gross output	N/A	N/A	X	X	X	X	X	X		X	For distributed PV; other costs analyzed: costs to manage non-controllable solar for reliability. Other benefits analyzed: long-term societal value, economic growth value
This VT Study	Utility/non-participating ratepayers	Gross output	x	X	X	X	X	X	X	X			

NOTE: The Department is aware of at least three additional, potentially relevant studies that will be published sometime in 2013.

3.2 Cross-subsidization analysis decisions

Based upon the landscape of methodologies revealed in the broad literature review, the Department made three threshold decisions regarding its cross-subsidization analysis framework, each described in greater detail below:

- To examine the cost-benefit from a statewide ratepayer perspective, with consideration of two scenarios which include and do not include monetary value for reductions in greenhouse gas emissions;
- To include a clear, defined set of assumptions of the costs and benefits of net metering; and
- To include costs and benefits associated with all generation by net metering systems, rather than only that generation that is exported to the electric grid.

The following subsections describe the conclusions the Department reached on each of these points.

The Department modeled the costs and benefits of net metered generation from three technologies: fixed solar photovoltaic (PV), 2-axis tracking solar PV, and wind power. While there are a handful of net-metered generators in Vermont that use agricultural methane or hydropower, over 95% of net-metered generation uses either solar or wind power. In addition, the Legislature has made special allowance for agricultural methane in the Standard Offer program. The Department expects that the vast majority of new net metering generation will continue to be powered by solar and wind energy.

3.2.1 Ratepayer perspective

There are a number of different cost-benefit tests that an analysis could pursue to determine the impact of net metering, each reflecting the different perspective.[13] The Department concluded that Act 125 requires a statewide ratepayer perspective. This is the appropriate analysis to evaluate any potential subsidization of net metering participants by other Vermont retail electric customers. For simplicity and clarity, the Department decided to consider the weighted average costs and benefits across all of the state's utilities rather than model the costs and benefits for each utility separately.

In addition, the Department supplements the state utility ratepayer perspective by the avoided costs of greenhouse gas emissions that are currently externalized due to market failures. This calculation attempts to quantify what the ratepayer costs and benefits would be if these costs were internalized in

[13] One perspective is that of the participant (net metered customer), who receives lower electric bills in exchange for expending the capital for the project. A ratepayer cost-benefit test captures costs and benefits to a utility's ratepayers (including both those who install net metered systems and those who do not). This perspective depends on the regulatory structure where utility recovers the costs from, and shares the benefits with, its customers. Moving to a larger universe of impacted people, a study can examine the impact on all the ratepayers in the state of Vermont. The largest scale is society as a whole.

Depending on the perspective considered for a cost-benefit analysis, a particular flow of value could be considered a cost, a benefit, or a transfer. For example, the utility's cost from lost bill revenue is the participant's benefit from reduced electric bills. Reduced Vermont contribution to regional transmission costs (for transmission already built) is a benefit if the boundary is drawn at the utility or state level, but is simply a transfer of burden to other New England ratepayers if society as a whole is considered. Under current policies, costs due to many environmental impacts, such as greenhouse gas emissions, are borne by society as a whole, not just by Vermont or any single utility's ratepayers.

the electricity market. The Department finds this addition appropriate given the State's emphasis on greenhouse gas emission reductions, exemplified in statutory priorities (see, for example, 10 V.S.A. § 578 and 30 V.S.A. § 8001), and especially the statutory guidance in 30 V.S.A. § 218c to consider "the value of the financial risks associated with greenhouse gas emissions from various power sources."

3.2.2 Costs and benefits

The Department examined the relevant literature, as well as the structure of New England and Vermont electricity markets and regulation to identify the following costs:

- Lost revenue (due to participants paying smaller electric bills)
- The Vermont solar credit, for solar PV systems
- Net metering-related administrative costs (engineering, billing, etc.)

The Department identified the following benefits:

- Avoided energy costs, including avoided costs of line losses and avoided internalized greenhouse gas emission costs
- Avoided capacity costs, including avoided costs of line losses
- Avoided regional transmission costs (costs for built or un-built pooled transmission facilities, or PTF, embodied in the ISO-NE Regional Network Service charge and other regional changes allocated in a similar fashion)
- Avoided in-state transmission and distribution costs (avoiding the construction of new non-PTF facilities)
- Market price suppression
- Value associated with SPEED generation

Net costs and benefits were calculated both including and excluding the value of avoided greenhouse gas emissions that are currently not internalized in the cost of energy. Ratepayers face a risk that more greenhouse gas costs will be internalized in the future, potentially leading to stranded assets.

Costs and benefits are determined from a Vermont ratepayer perspective; transfers from entities which are not Vermont ratepayers to Vermont ratepayers are included; any potential transfers between Vermont ratepayers are not included.

The assumptions used for each of these costs and benefits are described in more detail in Section 3.3 below.

3.2.3 Generation to include

The literature review conducted for this study revealed one particular analytic choice made by the Department that is different from some similar studies undertaken elsewhere: other analyses consider the costs and benefits of only the generation that is exported to the grid from the site of the net metering generator. That is, they do not consider the costs and benefits to the consumer, utility, or society of generation that offsets load on-site. The Department considered the analytical option used by others, but determined that this choice is not appropriate for Vermont because it would have been unresponsive to the charge from Act 125 which asks for an evaluation and analysis of 30 V.S.A. § 219a as a whole. Instead, the Department's analysis considers all generation from net metering systems. Other reasons for this choice include:

- The net metering solar credit is based on all generation;
- Simplified permitting is allowed for small net metering generators whether they produce enough to spin their host's meter backwards or not;
- Generation from a net metering system can offset not only a customer's load but also service and other charges;
- Group net metering and virtual group net metering options are available in Vermont. In these instances, generators are likely to be connected directly to the grid, and balancing of production with load is only accounted for on paper each billing period rather than physically in net electric energy flow through a meter.

3.3 Modeling assumptions

The spreadsheet model[14] estimates the costs and benefits incurred as a result of any single net metering installation installed in 2013 or a later year. It projects costs and benefits over the 20-year period following installation, allowing examination of the potential changing costs and benefits over that period as well as calculation of a levelized net benefit or cost per kWh over 20 years.

3.3.1 What the model does not do

While model calculations are precise, and reflect the Department's best point estimate, they do not estimate the width of the range of uncertainty surrounding each estimate due to the compounding effect of multiple assumptions, each of which has its own uncertainty. In addition, the model does not:

- Capture economic impacts outside of the utility-ratepayer context, such as job or economic impacts from the renewable electricity industry or changes to the economics of energy consumption among net metering participants or non-participants.
- Identify impacts on energy prices, load shapes, or other inputs to the analysis that may have already occurred due to deployment of net metering systems in Vermont. For systems modeled as installed in years after 2013, the model does not account for potential changes in Vermont's load shape or other inputs that may occur prior to installation.
- Capture potential changes in rate structures or regional costs, including those due to net metering. It models only the marginal impact of net metering under a "current policy" baseline scenario. That is, it does not model a situation in which rate structures change over time (such as adoption of time-of-use rates), or the impact that increasing net metering may have on future rates or rate structures.
- Capture nonlinear or feedback effects in which additional deployment of net metering in subsequent years may change marginal costs or benefits attributable to systems installed in earlier years (such as through changes in load shape and resulting peak coincidence). For example, it does not capture changes in the costs or benefits (such as avoided infrastructure costs) attributed to systems deployed in 2013 that might occur if future net metering, or other

[14] Available for download from http://publicservicedept.vermont.gov/topics/renewable_energy/net_metering.

generation or efficiency deployment, changes the state's load shape and therefore the need for or cost of infrastructure.

- Include impact from advanced metering infrastructure or other grid modernization technologies, and the resulting potential changes to rate structures.
- Account for integration costs (incremental costs due to the need to change the output of other resources to account for intermittency). These costs are expected to be very small for systems of the size eligible for net metering in Vermont.
- Include monetary values for environmental impacts other than avoided greenhouse gas emissions or value as SPEED resources.
- Capture differences between utilities. All numbers used are weighted statewide or region-wide averages.
- Capture potential cross-subsidization between utilities. This should be very small as the costs and benefits studied are utility-specific. Second-order effects of net metering are possible if net metering penetration or the distribution of net metering technologies is very different between utility service territories.

3.3.2 Economic assumptions

3.3.2.1 Inflation

The baseline expected long-term inflation estimate is 2.45%. This is based on the market expectations for inflation, measured by the difference between the return on inflation-protected and non-inflation-protected long-term (>10 year) U.S. Treasury bonds (as measured in late November, 2012).

3.3.2.2 Discount rate

The Department's analysis uses two discount rates. One, referred to as the "ratepayer" discount rate, is based on the cost of capital to individual ratepayers. The other, referred to as the "statewide" discount rate, is based on a societal perspective on time preference in which the state as a whole has less strong time preference than do individual ratepayers.

The ratepayer discount rate assumed in the Department's analysis is 8.03%. This rate was derived based on analysis conducted by the U.S. Department of Energy for use in analysis of the cost-effectiveness of appliance energy conservation standards.[15] The analysis that U.S. DOE conducts for these standards includes examination of the cost of capital faced by U.S. residential, commercial, and industrial energy consumers. The Department weighted the three average values used in recent U.S. DOE rulemaking proceedings by the three sectors' share of Vermont load, then adjusted for inflation.

The statewide discount rate assumed in the Department's analysis is 5.52%. The Department assumes that the state as a whole has a time preference similar to that of society at large. The Public Service

[15] See, for example, analysis conducted for the standards of furnace fans (https://www1.eere.energy.gov/buildings/appliance_standards/residential/furnace_fans.html) and electric motors (https://www1.eere.energy.gov/buildings/appliance_standards/commercial/electric_motors.html).

Board has adopted a value of 3% in real terms for societal screening of energy efficiency measures; this value is 3% adjusted for inflation.[16]

3.3.3 Costs and Benefits

In the context of this study, "costs" and "benefits" are measured from the ratepayer standpoint. The utility regulatory structure in Vermont (including GMP's alternative regulation plan, the co-op structure of VEC and WEC, and the municipal structure of the state's other utilities) results in the relevant set of costs and benefits faced by the state's utilities being passed to the state's ratepayers. For example, utility costs include lost revenue, the solar credit, and administrative costs. Benefits include avoided energy, capacity, transmission, and distribution costs. As a result, the proposed analytical framework treats utility costs as ratepayer costs, and utility benefits as ratepayer benefits.[17]

3.3.3.1 Costs

3.3.3.1.1 Reduction in utility revenue

Net metering reduces utility revenue by enabling a participating customer to provide some of their own electricity (including, at times, spinning their meter backward while exporting energy), which reduces their monthly bill. In order to calculate the size of this reduction due to a modeled net metering installation, the model requires the energy produced per year, along with the expected average customer rate, and any solar credit. The current average electric rate applicable to most net metering installations is 14.7 cents/kWh. This is the average residential electric rate; after the passage of Act 125 in the 2012 legislative session the vast majority of net metering installations in the state should be credited at the residential rate. This is because these installations are in fact residential, or because they are commercial accounts billed under a demand or time-of-use tariff – Act 125 established that such commercial customers receive credit for net metered generation at the residential rate.

Generally speaking, electric rates are composed of energy, capacity, transmission, and other costs. (Other costs include personnel/O&M and the carrying costs of the utility's investments in poles and wires.) In order to project costs and benefits into the future, the Department has built a simple tool to build a self-consistent projection of rates based on forecast market costs of energy and capacity, forecast transmission costs, and an assumption that other utility costs will rise at some rate, for which the Department chose to use the rate of inflation.

The analysis assumes that energy costs in rates are composed of a mixture of the market energy costs seen in New England over the preceding 10 years: 20% based on market energy prices in the year in question, 40% based on the average of the previous 5 years, and 40% based on the average of the previous 10 years. Vermont's utilities enter into contracts of varying lengths, and the prices they are willing to pay are based on the energy prices at the time, as well as projected energy prices. See the discussion of "avoided energy costs" below for detail regarding the market energy price forecast.

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[16] The discount rate is 5.52% rather than 5.45% because the two rates are most appropriately multiplied rather than added. $1.0245 \times 1.03 = 1.0552$.

[17] Externalities, such as the externalized portion of the value of greenhouse gas emission reductions, no not follow this pattern.

The analysis assumes that market capacity costs equivalent to 60% of Vermont's peak are included in rates; the remainder of capacity is self-supplied and therefore not subject to market fluctuations. (These self-supplied capacity costs are included in the "other" category for utility infrastructure, O&M, etc.) See the discussion of "avoided capacity costs" below for detail regarding the market capacity price forecast.

Regional transmission costs, embodied in the ISO-NE administered Regional Network Service charge, account for the independent transmission portion of electric rates. The analysis assumes that these costs are distributed in an even fashion across all of Vermont's kWh. See the discussion of "avoided regional transmission costs" below for detail regarding the RNS forecast.

Once 2012 energy, capacity, and transmission costs are removed from 2012 rates, the remainder must reflect other costs.[18] The Department assumed that these costs rise at the rate of general inflation. The analysis makes one adjustment to account for known current circumstances: the guaranteed merger savings resulting from the merger of GMP and CVPS. These savings come out of the "other" category, and are assumed to total $144 million in nominal dollars in 2012 to 2021, then to continue at the same annual nominal level in 2022 and later that they achieve in 2021.

The rate forecast resulting from this analysis is shown in Table 2, located in Section 3.3.3.2.1.

Solar photovoltaic net metering systems are eligible for a "solar credit" in addition to the value of their rates. This credit is calculated by subtracting the residential rate from 20 cents/kWh. Therefore, the state average solar credit in 2013 should be 5.3 cents per kWh generated. The value of this credit is fixed for ten years for each installation at the value it had at the time the system was commissioned. As a result, by the end of ten years the cost of each kWh provided by the solar net metering system could significantly exceed 20 cents. The solar credit is guaranteed to each system for ten years. For systems installed in later years, when rates are expected to be higher in nominal terms, the solar credit is assumed to be correspondingly smaller.

3.3.3.1.2 Administrative costs

The Department did not receive quantitative data from any commenter regarding appropriate administrative costs. The Department developed a set of assumed costs based on qualitative comments that the current administrative burden on distribution utilities is split between two main tasks: evaluating systems as they are submitted (a one-time cost related to engineering assessment and other setup costs) and billing (which is predominantly a cost for group net metered systems, as billing individual net metering is already or very easily automated). Based on qualitative comments, the Department assumed that the total cost for these two tasks is approximately $200,000 dollars per year for the current pace and scale of net metering in Vermont, split roughly in half between initial costs and on-going costs. To a rough approximation, this corresponds to a setup cost of approximately $20 per kW of net metering system capacity, ongoing costs of about $20 per kW per year for billing group net metered systems, and no on-going billing cost for individual net metered systems. The Department also assumed that efficiencies in billing systems (aided by the standardization resulting from the Board's

[18] These other costs are also reflected in the monthly customer charge, which does not play a significant role in the determination of net metering costs and benefits.

order regarding billing standards and procedures) would result in billing costs per kW falling at a rate of 20% per year.

3.3.3.2 Benefits

3.3.3.2.1 Avoided energy cost

From the perspective of the regional electric grid or a utility purchasing power to meet its load, net metering looks like a load reduction. A utility therefore purchases somewhat less power to meet the needs of their customers. While Vermont utilities purchase much of their energy through long-term contracts, this kind of moment-by-moment change in load is reflected in changes in purchases or sales on the ISO-NE day-ahead or spot markets. As a result, the Department assumes that the energy source displaced or avoided by the use of net metering is energy purchased on these ISO-NE markets (the difference between day-ahead and spot markets over the course of the year is minor).

Variable generators, like many of the types of generators deployed in Vermont for net metering, may exhibit some correlation with the weather and therefore with market prices. For example, the season and time of most solar irradiance is correlated (although imperfectly) with the peak summer loads, and therefore somewhat higher regional electricity prices. In order to capture this real correlation, the Department calculated a hypothetical 2011 avoided energy cost on an hourly basis by multiplying the production of real Vermont generators by the hourly price set in the ISO-NE market. This 2011 annual total value was then updated to 2013 and beyond by scaling the annual total price according to a market price forecast. The Department used hourly generation data from the Standard Offer program and net metering systems deployed around Vermont.[19] Significant deployment of such systems has continued this year, but relatively few systems operated for all of 2011. These calculations indicate that fixed solar PV has a weighted average avoided energy price 10% higher than the annual ISO-NE average spot market price, 2-axis tracking solar PV is 13% higher, and small wind is 5% lower.

The Department assumed that the capacity factor for each solar technology is projected capacity factor using the NREL PVWatts tool for a location in Montpelier, using all PVWatts default settings. The assumed capacity factor for wind is the 2011 capacity factor of the real Vermont generator used to calculate the correlation. Separating the capacity factor from the price-performance correlation allows the analysis to correct for differences between the typical capacity factors expected over many years for a generic facility and the capacity factors exhibited for a limited number of generators in only one year.

Output from net-metered generators is expected to decay at a low rate as the generator ages. The Department has assumed a rate of 0.5% per year; this is based on typical degradation rates for solar PV systems.

The Department's market energy price forecast is based on known forward market energy prices for the first five years, then known forward natural gas prices for years 5 to 10. Natural gas prices are an

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[19] Including a fixed solar array in Ferrisburgh, a two-axis solar tracker array in Shelburne, and a 100 kW wind turbine near the Burlington airport.

appropriate proxy for scaling electricity prices because the marginal generator in New England, which sets the price, is almost always a natural gas generator. Prices beyond 10 years are based on extrapolation of the electricity and natural gas price trends seen in the market-derived forecast for years 1-10. Using forward market prices implicitly includes the value of net metering as a known-price hedge against a volatile price of energy or natural gas. This is because the prices used in developing the Department's fit are the known prices to lock in supply years into the future; these prices already have a market-determined price risk adjustment included. The resulting energy price forecast (in nominal dollars) is shown in Table 2. The values used in this analysis are averages of the market price forecast conducted on three separate dates in October and November, 2012.

Energy generated by net metering systems on distribution circuits in Vermont is used locally, often on the same property or within a few miles. Therefore, line losses from this energy are insignificant. The energy being displaced, however, would be purchased on the bulk system and then transported to load, with resulting line losses. Analysis conducted by utilities and the Department for the development of the Vermont energy efficiency screening tool concluded that typical marginal line losses are about 9%. A very similar line loss factor applies to capacity; the Department has assumed it to be the same factor of 9%.

Table 2: *Department assumptions and forecasts of avoided energy, capacity, regional transmission, and in-state transmission and distribution costs, along with assumed self-consistent residential rate forecast, developed for this study. Values are in nominal dollars.*

	Residential Rates ($/kWh)	Energy ($/MWh)	Capacity ($/kW-month)	Regional transmission (PTF) ($/kW-month)	Vermont T&D (non-PTF) ($/kW-month)
2012	$0.147	$35.28	$2.89	$6.27	$13.17
2013	$0.147	$47.22	$2.84	$7.08	$13.43
2014	$0.150	$46.80	$2.84	$7.83	$13.71
2015	$0.151	$46.83	$2.84	$8.71	$13.88
2016	$0.150	$47.12	$1.16	$9.58	$14.14
2017	$0.154	$47.75	$1.71	$10.06	$14.48
2018	$0.157	$48.56	$2.39	$10.56	$14.58
2019	$0.162	$50.60	$2.68	$11.09	$14.95
2020	$0.168	$52.90	$3.76	$11.64	$15.33
2021	$0.170	$55.44	$3.83	$12.23	$15.64
2022	$0.179	$58.15	$5.75	$12.84	$15.95
2023	$0.186	$60.97	$6.92	$13.48	$16.19
2024	$0.193	$63.85	$7.57	$14.15	$16.50
2025	$0.201	$67.62	$7.86	$14.86	$16.86
2026	$0.208	$71.72	$8.03	$15.60	$17.18
2027	$0.216	$76.16	$8.20	$16.38	$17.50
2028	$0.225	$80.93	$8.38	$17.19	$17.82
2029	$0.234	$86.02	$8.56	$18.05	$18.14
2030	$0.244	$91.44	$8.75	$18.95	$18.46
2031	$0.254	$97.18	$8.94	$19.89	$18.78
2032	$0.265	$103.25	$9.13	$20.88	$19.10
2033	$0.276	$109.69	$9.33	$21.92	$19.42
2034	$0.288	$116.54	$9.53	$23.01	$19.74
2035	$0.301	$123.82	$9.74	$24.16	$20.07
2036	$0.314	$131.54	$9.95	$25.36	$20.39
2037	$0.328	$139.75	$10.16	$26.62	$20.71
2038	$0.342	$148.48	$10.38	$27.95	$21.02
2039	$0.357	$157.74	$10.61	$29.34	$21.34
2040	$0.373	$167.59	$10.83	$30.80	$21.65

3.3.3.2.2 Avoided capacity cost

Capacity costs are charged by ISO-NE to each of the region's utilities in order to offset the region's payments to generators through the Forward Capacity Market. (This market assures that enough capacity is available in the region to meet load during extreme weather or grid emergencies.) These costs are allocated to each utility based on its share of the ISO-NE regional peak load. The value provided by net metering systems is based on average performance (power output) during the time of peak system demand. For the bulk grid perspective, net metering systems look like a reduction in demand, and therefore reduce the utility's cost for capacity.

There are multiple potential methods to measure the effective capacity of generators with respect to different purposes. In determining the peak coincidence factors described in this or following subsections, the Department used the average performance of real in-state generators during particular times of day and particular months, as it determined were appropriate for the purpose at hand based on known cost allocation mechanisms or parallels with the treatment of energy efficiency. For example, the Department estimated economic peak coincidence for each generation technology by examining 2010, 2011 and 2012 performance of examples of each technology during afternoons in the month of July; ISO-NE peaks typically occur during July afternoons. These values were calculated based on the output of ten 2-axis tracking solar PV generators, four fixed solar PV generators, and two small wind generators. The resulting capacity peak coincidence values are shown in Table 3.

The capacity price forecast assumed by the Department, and used by default in the model, is based on recent electric utility regulatory filings including Integrated Resource Plans and purchase power acquisitions. The resulting capacity price forecast (in nominal dollars) is shown in Table 2.

Table 3: *Department assumptions of net-metered generators' performance during peak times used to calculate values of avoided capacity, avoided regional RNS cost, and avoided in-state transmission and distribution infrastructure. Each value shows the fraction of the system's rated capacity that is assumed in the calculation of the value of the three avoided costs. For example, in calculating the value of avoided capacity costs due to a fixed solar PV system with a nameplate capacity of 100 kW, the system is assumed to reduce capacity costs by the same amount as a system that can output 49.5 kW and is always running or perfectly dispatchable. These values were calculated based on the output of ten 2-axis tracking solar PV generators, four fixed solar PV generators, and two small wind generators.*

	Capacity	RNS	In-state T&D
Fixed PV	0.495	0.216	0.476
Tracking PV	0.595	0.263	0.562
Wind	0.045	0.069	0.050

3.3.3.2.3 Avoided regional transmission costs

Regional Network Service (RNS) costs are charged by ISO-NE to each of the region's utilities to pay for the cost of upgrades to the region's bulk transmission infrastructure. These are costs that have already been incurred, or are required to meet reliability standards, and thus cannot be entirely avoided – only their allocation among New England ratepayers can be changed. Avoiding these costs through net metering shifts the costs to ratepayers in other states. These costs are allocated to each utility based on its share of the monthly peak load within Vermont. The model uses values calculated by examining performance of Vermont generators during hour ranges when monthly peaks have occurred in Vermont over the last 5 years. The resulting average monthly peak coincidence values are shown in Table 3.

The values assigned to this cost are based on the ISO-NE forecast of the next 5 years' worth of RNS costs, and escalated based on historical increases in the Handy-Whitman Index of public utility construction costs. ISO-NE forecast RNS costs increase at 10% or more per year from 2012 to 2017, but the Department assumes that flattening regional peak loads, including demand response and distributed generation, will reduce this growth rate. The resulting regional transmission price forecast (in nominal dollars) is shown in Table 2.

3.3.3.2.4 Avoided in-state transmission and distribution costs

In-state transmission and distribution costs are those costs incurred by the state's distribution utilities or VELCO and which are not subject to regional cost allocation. The values used in this model are derived from those in the recently completed avoided transmission and distribution cost working group for the update to the electric energy efficiency cost-effectiveness screening tool. This working group consisted of representatives from the state's distribution, transmission, and efficiency utilities, and the Department. The values used in the model have been converted to nominal dollars using the assumed rate of inflation.

The in-state transmission and distribution upgrades deferred due to load reduction or on-site generation (such as net metering) are driven by reliability concerns. Therefore, rather than average peak coincidence for a net metering technology, the critical value is how much generation the grid can rely on seeing at peak times. Therefore, the Department calculated a "reliability" peak coincidence value, separate from the "economic" peak coincidence used in avoided capacity and regional transmission cost calculations. The Department calculated a reliability peak coincidence by calculating the average generator performance of several Vermont generators during June, July, and August afternoons. This corresponds to the methodology that ISO-NE uses to value energy efficiency in the Forward Capacity Market, results of which are used for transmission planning purposes. The resulting reliability peak coincidence values are shown in Table 3.

3.3.3.2.5 Market price suppression

Reductions in load shift the relationship between the supply curve and demand curve for both energy and capacity, resulting in changes in market price.[20] Because net metering looks like load reduction, the Department has approximated the market price suppression effect using analysis based on the 2011 Avoided Energy Supply Cost (AESC) study's calculation of the demand reduction induced price effect ("DRIPE") for Vermont. Energy DRIPE is a fraction of the value of avoided energy supply (starting at 9% and decaying over time), while capacity DRIPE has varying values over time, averaging to between $2 and $3 per kW-year. The assumptions regarding load, prices, and other factors used in the AESC study do not correspond directly to the assumptions used in this study, and load reduction with the particular load shapes corresponding to solar PV or wind generation are likely dissimilar from those from energy efficiency. As a result, the value attributed to net metering generation from this mechanism is very much approximate.

[20] This kind of market price suppression is a transfer between generators and ratepayers, so it is a benefit from a ratepayer perspective but would not be included in a societal cost-benefit analysis.

3.3.3.2.6 Value associated with meeting SPEED goals

The model allows for assignment of a value that ratepayers see that is attributable to the type of generation used by net metering systems installed by other customers. The analysis does not include, or attempt to quantify, the value of renewable attributes (such as RECs) to the participating customer, who is assumed to retain ownership of those attributes. Ratepayers see monetary value associated with the type of net metering technology and resource used by other customers' net metering through the fact that net-metered generation would help the state's utilities meet their SPEED goals. (The state has goals of 20% new SPEED resources by 2017 and 75% renewable electricity by 2032.) If a utility were to acquire SPEED resources elsewhere, there would likely be a small premium cost compared to market costs. This avoided premium is a benefit to all utility ratepayers from net-metered generation. Based on conversations with commenters the Department assumes this value is $5/MWh (fixed in nominal dollar terms).

3.3.3.2.7 Climate change

The Department's analysis calculates the costs and benefits of net metering to the state's non-participating ratepayers both with and without the estimated externalized cost of greenhouse gas emissions. It should be noted that these benefits from a marginal net metering installation in Vermont do not flow to Vermonter ratepayers in direct monetary terms. Instead, they reflect both a societal cost that is avoided and the size of potential risk that Vermont ratepayers avoid by reducing greenhouse gas emissions. If these environmental costs were fully internalized, for example into the cost of energy, ratepayers would bear those costs. The Department is assuming a value of $80 per metric ton of CO_2 emissions reduced (in $2011); this is the societal value adopted by the Public Service Board for use in energy efficiency screening, and is intended to reflect the marginal cost of abatement. About $2 of the $80 is internalized in utility costs through the Regional Greenhouse Gas Initiative, so the analysis incorporates an additional cost of about $78 (in $2011) for cases in which costs of environmental externalities are included.

CO_2 emission reductions are calculated by using the 2010 ISO-New England marginal emission rate of 943 lbs/MWh.[21] ISO-NE grid operations and markets almost always result in a gas generator dispatched as the marginal plant, so this value is comparable to the emissions from a natural gas generator. The Department's analysis does not track or account for emission or abatement of other greenhouse gasses.

3.4 Results of Cross-Subsidization Analysis

3.4.1 Systems Examined

This report presents the results of the cross-subsidization analysis for 6 systems, representing typical cases in Vermont:

- A 4 kW fixed solar PV system, net metered by a single residence
- A 4 kW 2-axis tracking solar PV system, net metered by a single residence
- A 4 kW wind generator, net metered by a single residence
- A 100 kW fixed solar PV system, net metered by a group

[21] http://www.iso-ne.com/genrtion_resrcs/reports/emission/final_2010_emissions_report_v2.pdf

- A 100 kW 2-axis tracking solar PV system, net metered by a group
- A 100 kW wind generator, net metered by a group

3.4.2 Results for Systems Installed in 2013

The methodology described in section 3.3 allows the model to calculate costs incurred and benefits received from each typical net-metered generator on an annual basis. These values may also be combined into a 20-year levelized value. A levelized value is the constant value per kWh generated that has the same present value as the projected string of costs and/or benefits over the 20-year study period. This section presents graphs of the annual costs and benefits along with levelized costs, benefits, and net costs (costs minus benefits). Benefits are presented both with and without externalized carbon emission costs; levelized values are also presented from both an individual ratepayer and statewide perspective (corresponding to different discount rates).

3.4.2.1 4 kW fixed solar PV system, net metered by a single residence

A 4 kW fixed solar PV system would generate about 4,500 kWh annually with a capacity factor of 13.0%.

Figure 5. *Annual costs and benefits associated with a 4 kW fixed solar PV residential system installed in 2013.*

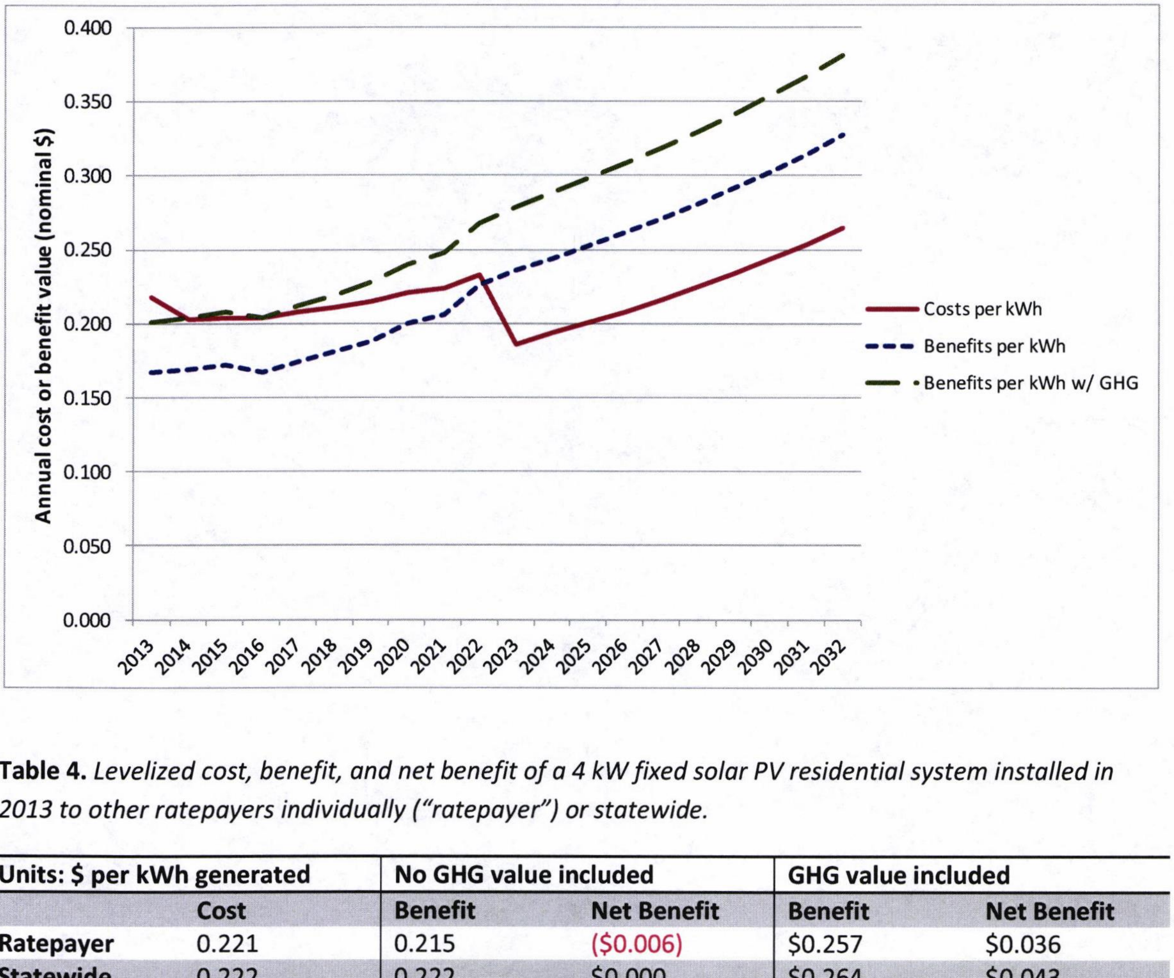


Table 4. *Levelized cost, benefit, and net benefit of a 4 kW fixed solar PV residential system installed in 2013 to other ratepayers individually ("ratepayer") or statewide.*

Units: $ per kWh generated		No GHG value included		GHG value included	
	Cost	**Benefit**	**Net Benefit**	**Benefit**	**Net Benefit**
Ratepayer	0.221	0.215	($0.006)	$0.257	$0.036
Statewide	0.222	0.222	$0.000	$0.264	$0.043

3.4.2.2 4 kW tracking solar PV system, net metered by a single residence

A 4 kW 2-axis tracking solar PV system would generate about 6,000 kWh annually with a capacity factor of 17.1%.

Figure 6. *Annual costs and benefits associated with a 4 kW tracking solar PV residential system installed in 2013.*

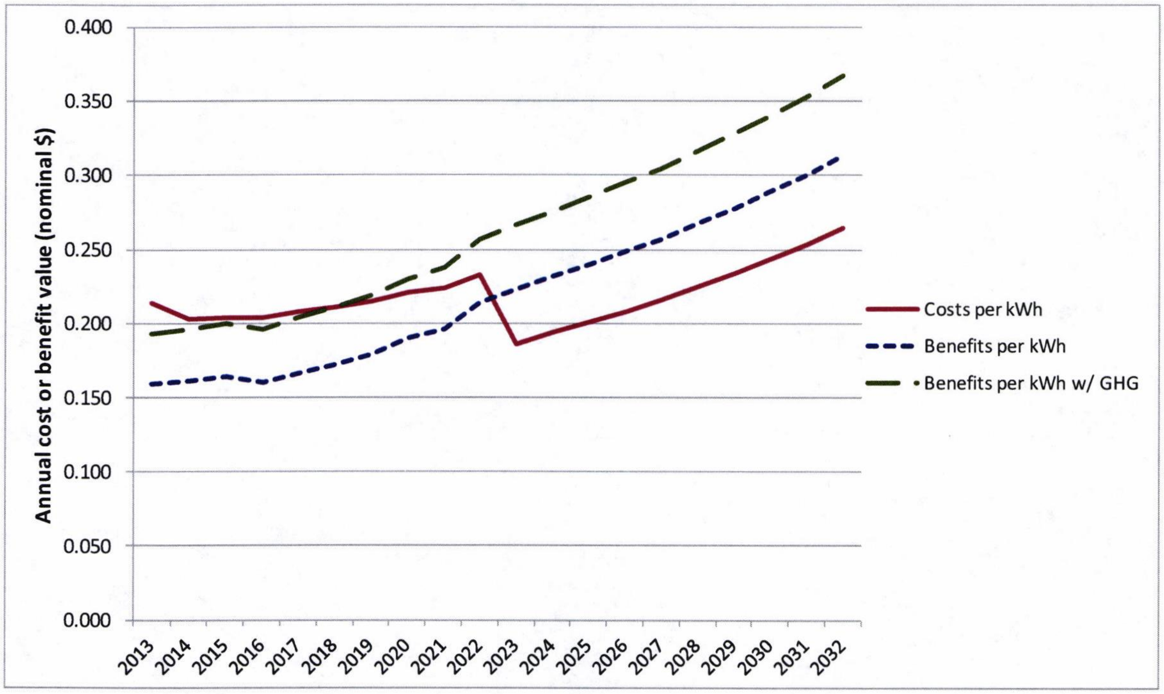


Table 5. *Levelized cost, benefit, and net benefit of a 4 kW tracking solar PV residential system installed in 2013 to other ratepayers individually ("ratepayer") or statewide.*

Units: $ per kWh generated		No GHG value included		GHG value included	
	Cost	**Benefit**	**Net Benefit**	**Benefit**	**Net Benefit**
Ratepayer	0.220	0.205	($0.016)	$0.247	$0.026
Statewide	0.221	0.211	($0.010)	$0.254	$0.033

3.4.2.3 4 kW wind generator, net metered by a single residence

A 4 kW wind generator generates approximately 2,600 kWh per year, with a capacity factor of 7.4%. If such a generator were sited optimally, it could have a significantly higher capacity factor and generate more electricity. However, the per-kWh costs and benefits described here would be unlikely to change significantly.

Figure 7. *Annual costs and benefits associated with a 4 kW residential wind generator installed in 2013.*

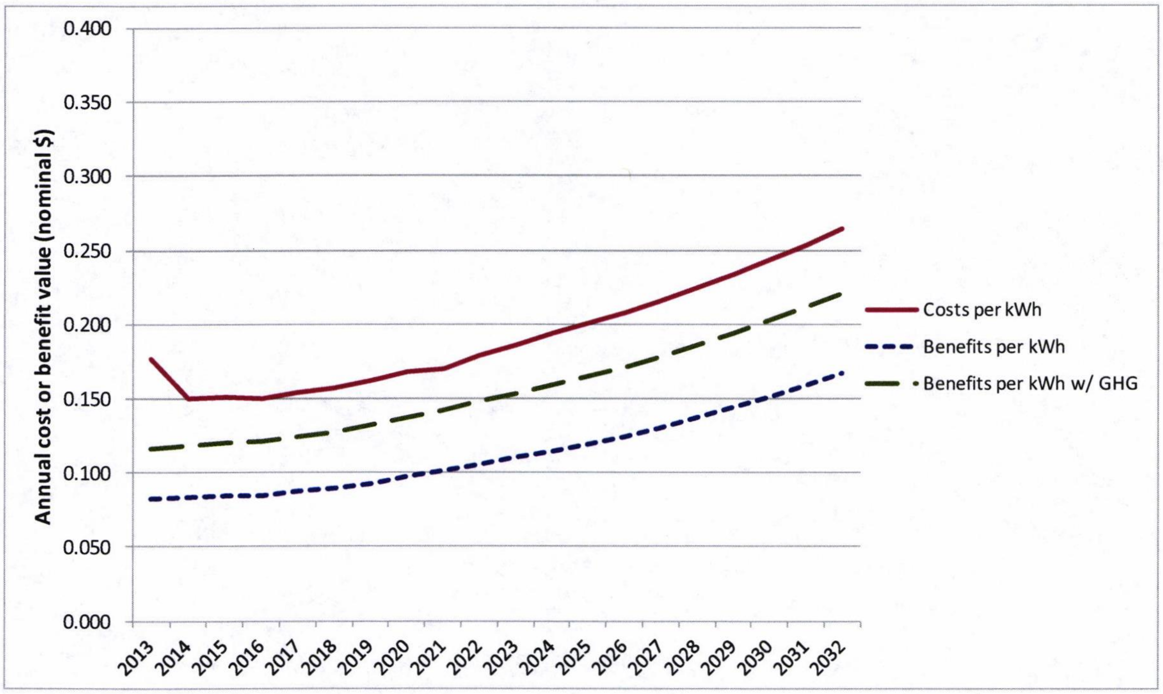


Table 6. *Levelized cost, benefit, and net benefit of a 4 kW residential wind generator installed in 2013 to other ratepayers individually ("ratepayer") or statewide.*

Units: $ per kWh generated		No GHG value included		GHG value included	
	Cost	**Benefit**	**Net Benefit**	**Benefit**	**Net Benefit**
Ratepayer	0.184	0.105	($0.079)	$0.147	($0.037)
Statewide	0.187	0.108	($0.079)	$0.151	($0.037)

3.4.2.4 100 kW fixed solar PV system, group net metered

A 100 kW fixed solar PV system would generate about 114,000 kWh annually with a capacity factor of 13.0%.

Figure 8. *Annual costs and benefits associated with a 100 kW fixed solar PV group net-metered system installed in 2013.*

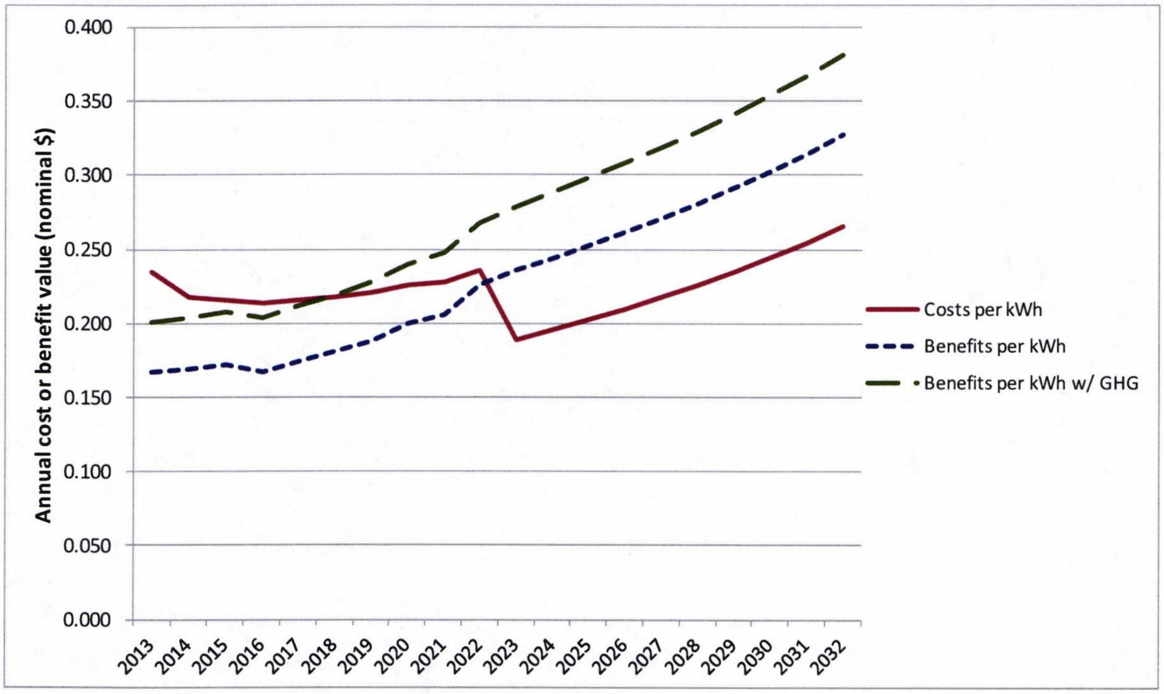


Table 7. *Levelized cost, benefit, and net benefit of a 100 kW fixed solar PV group net-metered system installed in 2013 to other ratepayers individually ("ratepayer") or statewide.*

Units: $ per kWh generated		No GHG value included		GHG value included	
	Cost	Benefit	Net Benefit	Benefit	Net Benefit
Ratepayer	0.228	0.215	($0.013)	$0.257	$0.029
Statewide	0.228	0.222	($0.006)	$0.264	$0.036

3.4.2.5 100 kW tracking solar PV system, group net metered

A 100 kW 2-axis tracking solar PV system would generate about 150,000 kWh annually with a capacity factor of 17.1%.

Figure 9. *Annual costs and benefits associated with a 100 kW tracking solar PV group net-metered system installed in 2013.*

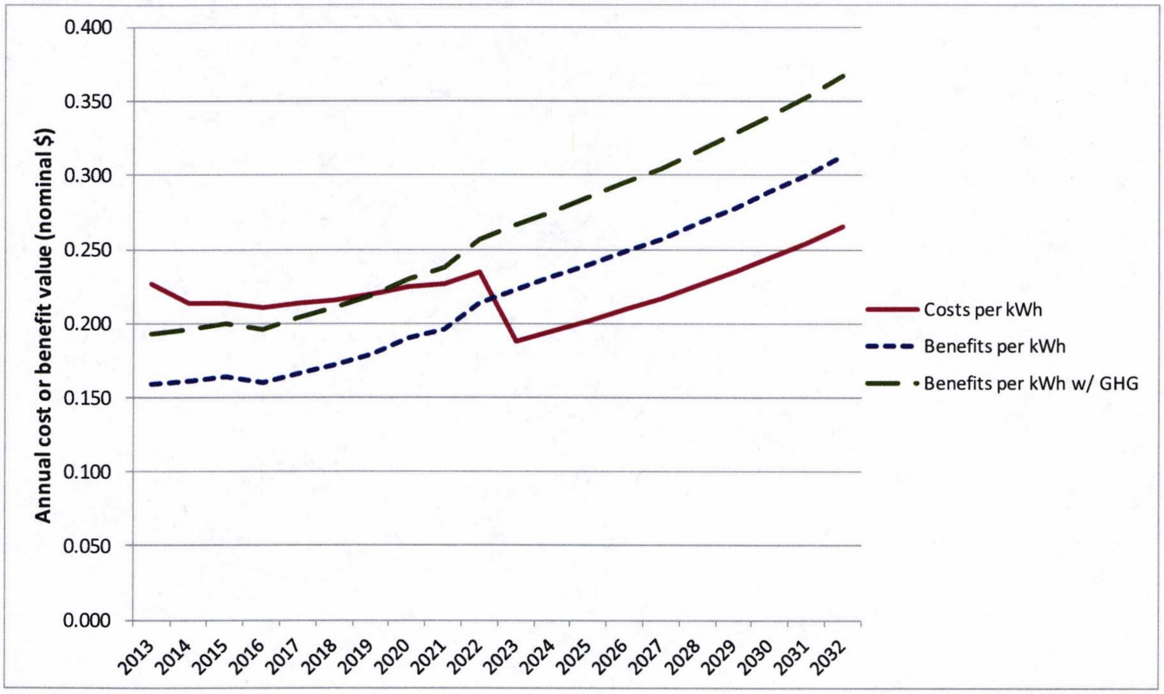


Table 8. *Levelized cost, benefit, and net benefit of a 100 kW tracking solar PV group net-metered system installed in 2013 to other ratepayers individually ("ratepayer") or statewide.*

Units: $ per kWh generated		No GHG value included		GHG value included	
	Cost	**Benefit**	**Net Benefit**	**Benefit**	**Net Benefit**
Ratepayer	0.226	0.205	($0.021)	$0.247	$0.021
Statewide	0.226	0.211	($0.015)	$0.254	$0.028

3.4.2.6 100 kW wind generator, group net metered

A 100 kW wind generator generates approximately 65,000 kWh per year, with a capacity factor of 7.4%. If such a generator were sited optimally, it could have a significantly higher capacity factor and generate more electricity. However, the per-kWh costs and benefits described here would be unlikely to change significantly.

Figure 10. *Annual costs and benefits associated with a 100 kW group net-metered wind generator installed in 2013.*

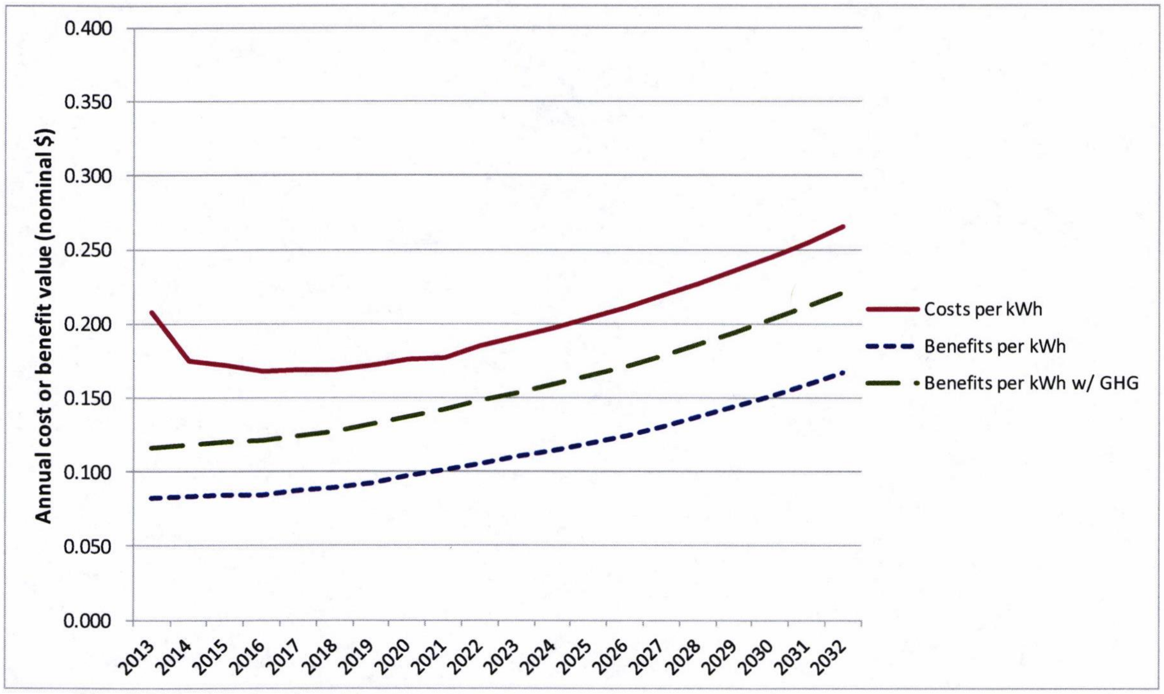


Table 9. *Levelized cost, benefit, and net benefit of a 100 kW group net-metered wind generator installed in 2013 to other ratepayers individually ("ratepayer") or statewide.*

Units: $ per kWh generated		No GHG value included		GHG value included	
	Cost	Benefit	Net Benefit	Benefit	Net Benefit
Ratepayer	0.197	0.105	($0.092)	$0.147	($0.050)
Statewide	0.199	0.108	($0.091)	$0.151	($0.048)

3.4.3 Systems Installed in Coming Years

Costs of energy, capacity, and transmission which contribute to electric rates may also be avoided by a net metered generator. These costs are projected to change over time. In addition, as electric rates rise the solar credit that applies to a newly installed net metered solar generator is expected to fall. This leads to the question of how the analysis of cross-subsidization presented in the previous section is likely to change for systems installed in future years.

While the analysis described in this section is necessarily more uncertain than the analysis presented in the previous section, it does provide some directional information and insights regarding future costs and benefits. The limitations of the model the Department developed for the cross-subsidization analysis also limit this analysis. In particular, the avoided transmission and distribution costs attributable to net metered generation depend on the State's and utilities' load shapes (particularly including the timing of monthly and seasonal demand peaks). Load shapes will change as net metering is deployed, saturation of appliances changes, and electric energy efficiency measures are implemented. Projections of costs and benefits are necessarily more uncertain as they reach further into the future.

In order to undertake this secondary analysis, the Department modeled the costs and benefits, as in Section 3.3, but for systems installed in years after 2013. The following figures illustrate the changes in net costs and benefits for residential-scale systems installed in subsequent years. (The results of large-scale systems are similar, as illustrated in the previous section, and are omitted here for brevity.) Qualitatively, the benefits of solar PV net metered generation increase more quickly than the costs (due in large part to the decreasing solar credit), so that solar PV systems installed in later years have greater net benefit than systems installed in 2013. The same is not true for wind generation.

Figure 11. *Levelized net benefit of a 4 kW individual net metered fixed solar PV system installed in each year 2013 to 2018. Four lines show the net benefits from the perspective of a typical Vermont ratepayer, from the statewide perspective of all ratepayers, and both including and excluding the value of GHG emission reductions due to system operation.*

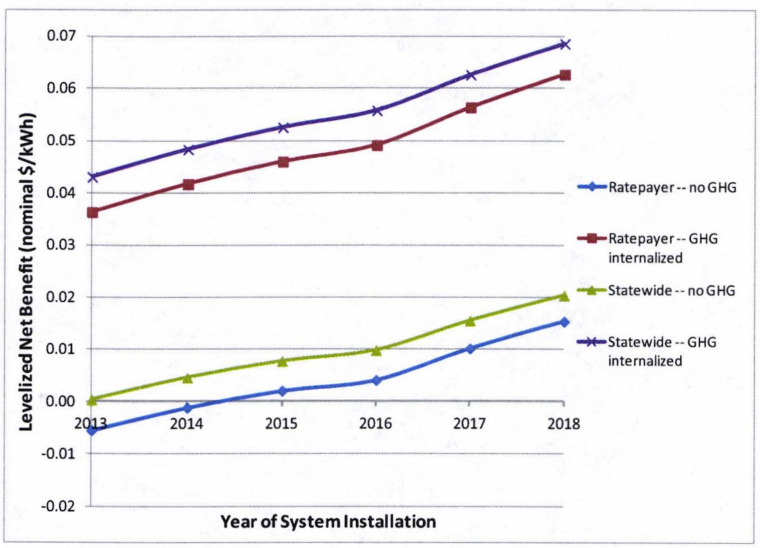


Figure 12. *Levelized net benefit of a 4 kW individual net metered 2-axis tacking solar PV system installed in each year 2013 to 2018. Four lines show the net benefits from the perspective of a typical Vermont ratepayer, from the statewide perspective of all ratepayers, and both including and excluding the value of GHG emission reductions due to system operation.*

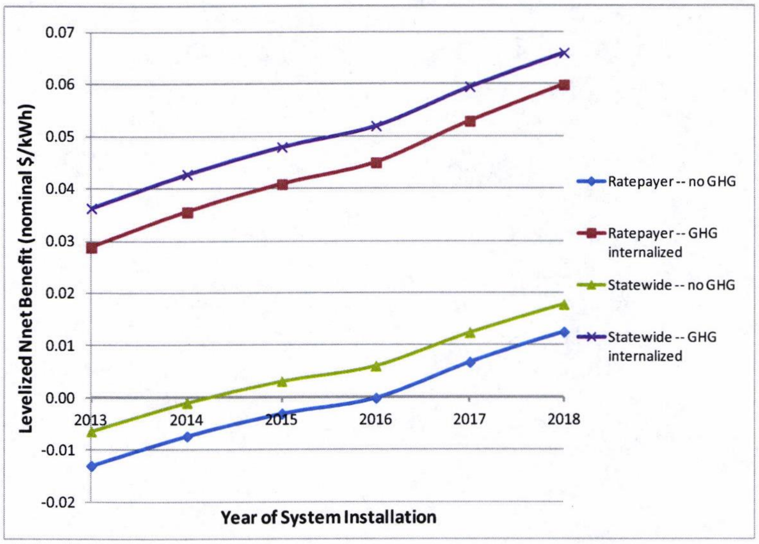
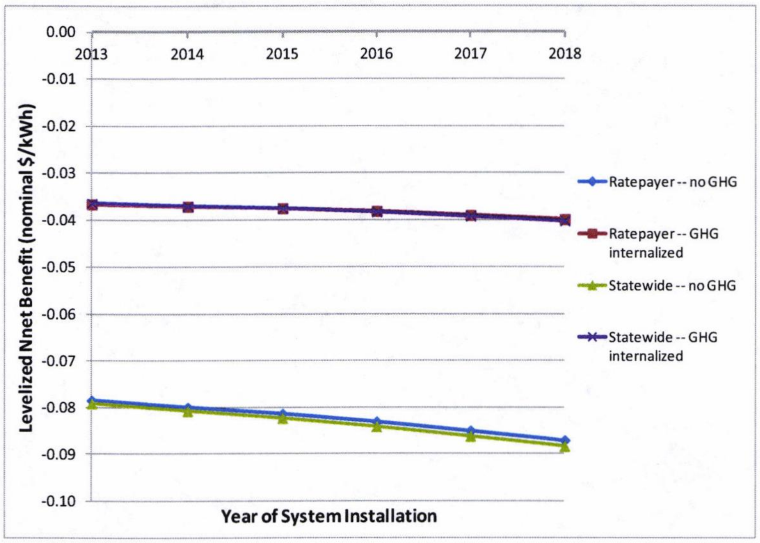


Figure 13. *Levelized net benefit of a 4 kW individual net metered wind generator system installed in each year 2013 to 2018. Four lines show the net benefits from the perspective of a typical Vermont ratepayer, from the statewide perspective of all ratepayers, and both including and excluding the value of GHG emission reductions due to system operation.*



3.4.4 Concluding Remarks on Cross-Subsidization

The analysis presented in the preceding sections indicates that net metered systems do not impose a significant net cost to ratepayers who are not net metering participants. Net benefits from solar photovoltaic systems, which represent nearly 88% of net metering systems, are either positive or negative depending on the discount rate chosen and whether the value of non-internalized greenhouse gas emissions are included or not included respectively. There would be real long-term risk to ratepayers if decisions were made that assume no increase in the internalization of these costs over the 20-year analysis period for this study. Impacts on transmission and distribution infrastructure costs are a significant component of the value of net-metered systems. Solar PV has much greater coincidence of generation with times of peak demand than does wind power; this results in more net benefits for solar PV than for wind. Wind power has net costs whether greenhouse gas emissions costs are included or not. Given the relatively small scale of wind system net metering in Vermont, the Department does not consider this to be a significant cost to ratepayers.

4 General assessment of Vermont's net metering statute, rules, and procedures

The Department has reviewed the relevant statutes, rules, and general policy in Vermont, and the results of the cross-subsidization analysis described in Section 3. The Department's general assessment is that Vermont's current net metering policy is a successful aspect of State's overall energy strategy that is cost-effectively advancing the state's renewable energy goals. Net metering in Vermont has undergone a significant growth, enabled in part by changes in state policy and statutes, as well as by changes in technology costs and business models. In addition to the costs and benefits discussed in the preceding sections, net metering has enabled the growth of numerous small businesses, which employ hundreds of Vermonters and form an important part of the foundation of Vermont's clean energy economy. Based on this success and the analysis presented in this report, the Department has concluded that there is no need for statutory changes at this time.

The Department highlights the process, led by the Public Service Board (PSB), to clarify and make more uniform the billing standards and practices associated with net metering. The PSB issued an order with billing standards and procedures on November 14, 2012, and has the authority to revise these standards as may be warranted. While additional changes may be required as utilities and regulators understand billing cases and configurations not yet covered in the standards, utilities should expeditiously update their tariffs and procedures to match the Board's order. These efforts should provide clarity and uniformity; lack of clarity and uniformity had been an area of concern to the Department. Stability in utility procedures and state policies would provide an opportunity to better understand the impacts of current policies and allow regulatory processes to come up to date. For example, such stability should allow the PSB to update their net metering rule (5.100) to reflect statutory changes and updated interconnection standards since the rule was last updated. The PSB has the authority to raise the 4% capacity cap for each utility, reducing any future need to raise that cap through statutory change.

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO MODIFY ITS NET METERING SERVICE AND TO INCREASE THE GENERATION CAPACITY LIMIT.	))))))	CASE NO. IPC-E-12-27

Idaho Conservation League

Direct Testimony of R. Thomas Beach

May 10, 2013

CONFIDENTIAL

EXHIBIT 203

ANALYSIS OF CUSTOMER BILLS BEFORE AND AFTER SOLAR NEM SYSTEM USING IDAHO POWER CONFIDENTIAL RESPONSE TO ICL PRODUCTION REQUEST NO. 13.

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO MODIFY ITS NET METERING SERVICE AND TO INCREASE THE GENERATION CAPACITY LIMIT.	))))))	CASE NO. IPC-E-12-27

Idaho Conservation League

Direct Testimony of R. Thomas Beach

May 10, 2013

EXHIBIT 204

IDAHO POWER RESPONSE TO ICL PRODUCTION REQUETS NO 1

<u>REQUEST NO. 1</u>: Please provide the most recently used alternate costs for analyzing demand side resources. Please provide these costs for each hour of the year and for the future 20 years. Please provide these costs in excel spreadsheet or other digital format.

<u>RESPONSE TO REQUEST NO. 1</u>: The most recent costs for analyzing demand-side resources were produced in the 2011 Integrated Resource Planning ("IRP") process. In addition, Attachment 1 (attached hereto) contains hourly avoided costs from January 1, 2011, to December 31, 2029. Attachment 2 (attached hereto) contains copies of the 2011 IRP Appendix C, pages 66 to 71. This section of Appendix C explains the derivation of the Demand-Side Management ("DSM") alternative costs. These costs are averaged in time-of-use type pricing categories for analysis of DSM resources. Please note, the Summer On-Peak prices are calculated using Idaho Power's 30-year levelized capacity, variable energy, and operating costs of a 170 megawatt ("MW") Simple Cycle Combustion Turbine.

The response to this Request was prepared by Pete Pengilly, Customer Research and Analysis Leader, Idaho Power Company, in consultation with Lisa D. Nordstrom, Lead Counsel, Idaho Power Company.

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO MODIFY ITS NET METERING SERVICE AND TO INCREASE THE GENERATION CAPACITY LIMIT.	))))))	CASE NO. IPC-E-12-27

Idaho Conservation League

Direct Testimony of R. Thomas Beach

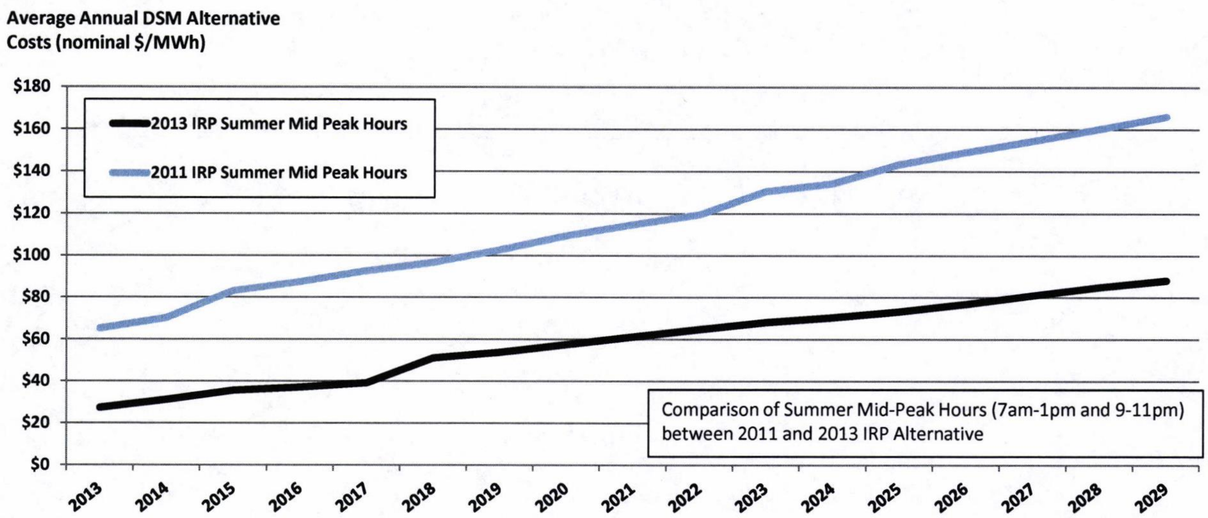
May 10, 2013

EXHIBIT 205

IDAHO POWER 2013 IRP DSM STATUTS UPDATE
OCTOBER 11, 2013

2013 IRP DSM Status Update, slide 4

2013 IRP DSM Status Update – 2011 vs. 2013 IRP Cost Comparison



CERTIFICATE OF SERVICE

I hereby certify that on this 10th day of May 2013, I delivered true and correct copies of the foregoing DIRECT TESTIMONY OF R. THOMAS BEACH ON BEHALF OF THE IDAHO CONSERVATION LEAGUE to the following persons via the method of service noted:

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